Appendix C:

SUPPORTING MATERIAL FOR BACT REVIEW FOR LARGE GAS TURBINES USED IN ELECTRIC POWER PRODUCTION

1. INTRODUCTION

This technical appendix provides the basis for the best available control technology (BACT) information presented in Chapter III of the Air Resources Board's (ARB or Board) Guidance for Power Plant Siting and Best Available Control Technology. The appendix covers control methods for oxides of nitrogen (NO_X), carbon monoxide (CO), volatile organic compounds (VOC)[1], particulate matter of ten microns or less (PM_{10}), and oxides of sulfur (SO_X) emissions. Furthermore, it is intended to provide information to be used in determining BACT for stationary, natural gas-fired turbines (herein referred to as "gas turbines") used in electric power production of at least 50 megawatts (MW) in size.

It is the responsibility of the permitting agency to make its own BACT determination for the "class or category of source" of gas turbine application. Some factors that should be considered in determining gas turbine "class or category of source" are load variability, manned versus remote control, and catalyst compatibility with flue gas characteristics. The latter concern makes it necessary to consider BACT for simple-cycle configurations separately from combined-cycle and cogeneration configurations, at least for NO_X, CO, and VOC.

In evaluating BACT for gas turbines, staff reviewed control technologies and corresponding emission levels for each pollutant in the areas of:

- current State Implementation Plan (SIP) control measures,
- control techniques required as BACT,
- emission levels achieved in practice, and
- more stringent control techniques which are technologically and economically feasible but are not yet achieved in practice.

Information in these four areas was obtained primarily from California air quality management and air pollution control district (district) rules, personal contacts with California and out-of-state

[1]Regulatory agencies use varying terminology for volatile organic compounds. Some common terms to mention include: reactive organic gases (ROG), non-methane hydrocarbons (NMHC), and precursor organic compounds (POC).

regulatory agency staff, consultants, basic equipment vendors, control technology vendors, and proposed and existing power plant operators and proponents. In addition, BACT determinations listed in the California Air Pollution Control Officers Association (CAPCOA) BACT Clearinghouse and U.S. EPA RACT/BACT/LAER Clearinghouse were reviewed. Staff's review of the Clearinghouse BACT determinations was limited to gas turbines of approximately 20 MW fired on natural gas and used in simple-cycle, combined-cycle, and cogeneration power plant configurations. The information gathered from these avenues was used in recommending the proposed BACT emission levels.

A layout showing major process equipment for a typical stationary gas turbine combined-cycle power plant is provided in Figure 1 for reference purposes. A listing of acronyms and abbreviations used in Appendix C is included at the end of the appendix.

II. POTENTIAL METHODS OF NO_X EMISSION CONTROL

Traditionally, the pollutant of most concern from gas turbines is NO_X. NO_X emissions are of particular concern due to their contribution to ground-level ozone formation, stratospheric ozone depletion, and acid rain. In the lower atmosphere, NO_X combines with reactive organic gases in the presence of sunlight to form ground-level ozone, which is the primary component of urban smog. In addition, nitric oxide and nitrogen dioxide are components of acid rain. These nitrogen oxides rise into the atmosphere and are oxidized in clouds to form nitric acid.

A. NO_X Formation Mechanisms

NO_X collectively refers to the combustion products nitric oxide (NO) and nitrogen dioxide (NO_2). NO_X emissions from fossil fuel combustion originate in three primary ways: from fuel-bound nitrogen, as prompt NO_X, and as thermal NO_X. NO_X from fuel-bound nitrogen is important in some liquid and solid fuels, but is minimal in gaseous fuels. Fuel NO_X is formed from the nitrogen bound in the fuel of combustion. NO_X is created when the fuel molecule is oxidized, releasing the reactive nitrogen. Prompt NO_X is a component of thermal NO_X formed at the combustion flame front (promptly) from early reactions of fuel-derived nitrogen intermediaries and hydrocarbon radicals during combustion. Prompt NO_X is recognized to be a minor component of total NO_X and is independent of combustion temperature. The most abundant means of NO_X production, especially for internal combustion, is thermal-induced NO_X. Thermal NO_X is created by high temperatures in the presence of free oxygen. The proportion of thermally induced NO_X is even greater when combusting gaseous fuels.

Atmospheric conditions which affect NO_X emissions are humidity, temperature, and pressure. Atmospheric water vapor has a quenching effect; the energy required to heat the airborne water has a tendency to lower combustor temperatures. At low humidity, NO_X emissions increase with increasing temperature. At high humidity, the effect of temperature is varied; NO_X emissions decrease with increasing ambient temperature above 50 °F, and increase with increasing temperature within the range below 50 °F. Increased atmospheric pressure results in higher pressure and temperature levels within the combustor, so NO_X emissions increase.

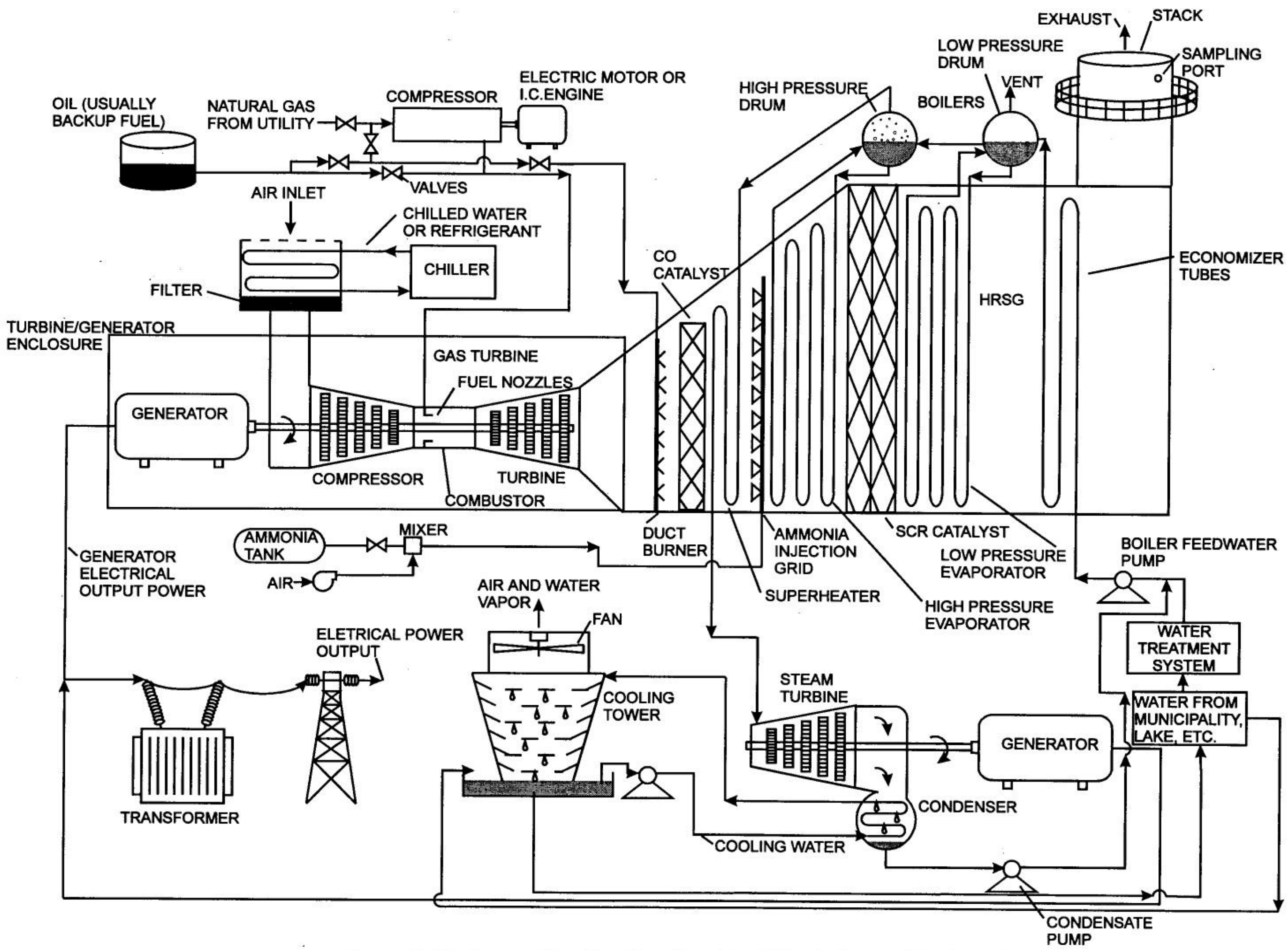

Figure 1 Stationary Gas Turbine Combined-Cycle Power Plant

There is a direct relationship between the power output level of a gas turbine, the firing temperature, and the combustor flame temperature. Gas turbines each have a base-rated power output level with corresponding NO_X emissions. At power outputs below base-rated power, flame temperatures are lower and thus NO_X emissions are lower. However at peak power outputs, NO_X emissions are greater due to increased flame temperatures.

B. Gas Turbine Combustor NO_X Controls

Combustion modifications reduce the concentration of NO_X emissions in the gas turbine flue gas by decreasing combustion temperature or decreasing the quantity of oxygen available for combustion.

1. Diluent Injection

Higher combustion temperatures result in greater thermodynamic efficiency. In turn, more work is generated by the gas turbine at a lower cost. However, the higher the gas turbine inlet temperature, the more NO_X that is produced. Diluent injection, or wet controls, can be used to reduce NO_X emissions from gas turbines. Diluent injection involves the injection of a small amount of water or steam via a nozzle into the immediate vicinity of the combustor burner flame. NO_X emissions are reduced by instantaneous cooling of combustion temperatures from the injection of water or steam into the combustion zone. The effect of the water or steam injection is to increase the thermal mass by mass dilution and thereby reduce the peak flame temperature in the NO_X forming regions of the combustor. Water injection typically results in a NO_X reduction efficiency of about 70 percent, with emissions below 42 ppmvd NO_X at 15 percent oxygen. Steam injection has generally been more successful in reducing NO_X emissions and can achieve emissions less than 25 ppmvd NO_X at 15 percent oxygen (approximately 82 percent control).

Combustor geometry, injection nozzle design, and the fuel nitrogen content can affect diluent injection performance. Water or steam must be injected into the combustor so that a homogeneous mixture is created. Nonuniform mixing of water and fuel creates localized "hot spots" in the combustor that generate NO_X emissions. Increased NO_X emissions require more diluent injection to meet a specified level of emissions. When diluent injection is increased, dynamic pressure oscillations in the combustor increase. Dynamic pressure oscillations can create noise and increase the wear and tear and required maintenance on the equipment. Continued increase of diluent injection will eventually lead to combustor flame instability and emission increases of CO and unburned hydrocarbons due to incomplete combustion.

Water is a better heat sink than steam; therefore more steam is required to reach a particular level of NO_X emissions. However, newer gas turbines usually apply steam injection. Steam injection is generally a better alternative since it does not increase the heat rate as much as water, carbon monoxide emissions are increased a smaller amount, pressure oscillations are less severe, and maintenance is reduced.

A negative attribute of water or steam injection is that the water or steam must be very pure before injection into the turbine. Any contaminants in the water or steam will cause a buildup of deposits on the turbine blades and other equipment. Deposits on the gas turbine blades reduce turbine efficiency, increase down time for maintenance, and can lead to failure of the equipment in extreme circumstances.

2. Dry Low-NO_X Combustors

The combustion chamber, or combustor, is the space inside the gas turbine where fuel and compressed air are burned. The combustion chamber can take the shape of a long can, an axially-centered ring of long cans (can-annular combustor), an annulus located behind the compressor and in front of the gas turbine (annular combustor), or a vertical silo.

Conventional combustors are diffusion controlled. This means fuel and air are injected into the combustor separately and mix in small, localized zones. The zones burn hot and produce more NO_X. In contrast, dry low-NO_X combustors minimize combustion temperatures by providing a lean premixed air/fuel mixture, where air and fuel are mixed before entering the combustor. This minimizes fuel-rich pockets and allows the excess air to act as a heat sink. The lower temperatures reduce NO_X formation. However, because the mix is so lean, the flame must be stabilized with a pilot flame. Dry low-NO_X combustors can achieve emissions of about 9 ppmvd NO_X at 15 percent oxygen (approximately 94 percent control).

To achieve low NO_X emission levels, the mixture of fuel and air introduced into the combustor (e.g., air/fuel ratio) must be maintained near the lean flammability limit of the mixture. Lean premixed combustors are designed to maintain this air/fuel ratio at rated load. At reduced load conditions, the fuel input requirement decreases. To avoid combustion instability and excessive CO emissions that occur as the air/fuel ratio reaches the lean flammability limit, lean premixed combustors switch to diffusion combustion mode at reduced load conditions. This switch to diffusion mode means that the NO_X emissions in this mode are essentially uncontrolled.

3. Catalytic Combustion

In catalytic combustion, a catalyst is used to promote oxidation of the inlet gas stream at lower temperatures than are required in standard thermal combustion. The catalyst bed is used to oxidize a lean air/fuel mixture within the combustor instead of burning it with a flame, as in a conventional combustor. The catalyst limits the temperature in the combustor and helps to stave off the production of thermal NO_X. Catalytic combustion can achieve NO_X emission of about 3 ppmvd NO_X at 15 percent oxygen (approximately 98 percent control), as claimed by manufacturers.

3. Duct-Burner NO_X Controls

1. Duct Burner Operation

Combined-cycle and cogeneration power plants are equipped with heat recovery steam generators (HRSG) to extract more energy from the hot exhaust gases leaving the gas turbine and create steam for use in other industrial processes or to turn a steam turbine to generate electricity. Feed water pumps send water through heat exchangers in the HRSG. The heat exchangers are generally large tubes made of conductive metals. Hot gases exchange heat energy with the water in the tubes before exiting through the stack. Duct burners can be used to increase the steam capacity of the HRSG. The duct burners are installed at the front of the HRSG to supply additional heat to the flue gas exiting the gas turbine. Because the duct burners are fuel-fired, they will produce NO_X emissions in addition to those from combustion in the gas turbine.

2. Low-NO_X Burners

Low-NO_X burners reduce NO_X by completing the combustion process in stages. Staged combustion can achieve lower NO_X emissions by dividing the combustion process into a number of stages where the air to fuel ratio is varied to reduce NO_X formation. This staging partially delays the combustion process and results in a cooler flame that suppresses thermal NO_X formation. After the initial combustion zone where the fuel is ignited, a pyrolitic zone is formed where the fuel is chemically broken down by heat from the flame. In the next stage, a fuel-rich (oxygen lean) zone is formed which limits the formation of NO_X. The last stage consists of a burnout zone where completion of combustion occurs.

The configuration of combined-cycle and cogeneration power plants is such that the gas turbine and duct burner exhaust through a common stack. Therefore, NO_X emissions from the duct burner are also further reduced with add-on controls which are otherwise utilized to reduce NO_X emissions from the gas turbine. Staff is not aware of any source test data attributing individual emission control efficiency to low-NO_X burners as part of the overall control of NO_X emissions from a gas turbine with a HRSG.

D. Flue-Gas NO_X Controls

1. Selective Catalytic Reduction

Selective catalytic reduction (SCR) systems selectively reduce NO_X by injecting ammonia (NH_3) into the exhaust gas stream upstream of a catalyst. NO_X, ammonia, and oxygen react on the surface of the catalyst to form molecular nitrogen (N_2) and water. The primary chemical reactions are shown below.

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

The catalyst, comprised of parallel plates or honeycomb structures, is installed in the form of rectangular modules, downstream of the gas turbine in simple-cycle configurations, and into the HRSG portion of the gas turbine downstream of the superheater in combined-cycle and cogeneration configurations.

In honeycomb-type catalysts, the size of the catalyst openings (i.e., pitch) is important. Smaller pitch equates to larger surface area, and thus greater NO_X removal efficiency due to maximizing of the surface area on which the reactions take place. At the other extreme, if catalyst openings are too small, potential for clogging from contaminants becomes an issue. The residence time of the exhaust gases in the presence of the catalyst must be sufficient for the reactions to take place. The longer the exposure time of the exhaust with the catalyst, the greater the NO_X removal is. Residence time is defined as the volume of the catalyst (e.g., ft^3) divided by the exhaust flow rate (ft^3/min). Space velocity is the inverse of residence time. Efficient NO_X removal is usually indicated by a space velocity of approximately 30,000 per hour.

The turbine exhaust gas must contain a minimum amount of oxygen and be within a particular temperature range in order for the selective catalytic reduction system to operate properly. The temperature range is dictated by the catalyst, which is typically made from noble metals, base metal oxides, or zeolite-based material. The typical temperature range for base-metal catalysts is 600 to 800 °F. Keeping the exhaust gas temperature within this range is important. If it drops below 600 °F, the reaction efficiency becomes too low and increased amounts of NO_X and ammonia will be released out the stack. If the reaction temperature gets too high, the catalyst may begin to decompose. Turbine exhaust gas is generally in excess of 1000 °F. HRSG cool the exhaust gases before they reach the catalyst by extracting energy from the hot turbine exhaust gases and creating steam for use in other industrial processes or to turn a steam turbine. In simple-cycle power plants where no heat recovery is accomplished, high temperature catalysts (e.g., zeolite) which can operate at temperatures up to 1100 °F, are an option. Selective catalytic reduction can typically achieve NO_X emission reductions in the range of about 80 to 95 percent.

a. Ammonia By-Product Emissions

Selective catalytic reduction uses ammonia as a reducing agent in controlling NO_X emissions from gas turbines. The portion of the unreacted ammonia passing through the catalyst and emitted from the stack is called ammonia slip. Currently, ammonia is not regulated by district new source review rules. New source review rules regulate criteria pollutants and their regulatory precursors. Although ammonia is recognized to contribute to ambient PM_{10} concentrations, it is not listed in any California new source review rule as a precursor to PM_{10}. As a result districts have regulated ammonia since the mid-1980's under nuisance and toxic air contaminant rules. The only exception is in the South Coast Air Quality Management District, where ammonia is specifically regulated under a new source review rule.

i. Regulation as a Toxic Substance

Ammonia is not a federal hazardous air pollutant or a State identified toxic air contaminant. However, due to acute and chronic non-cancer health effects, ammonia is potentially regulated under district risk management programs. Such programs may include toxic new source review rules/policies and the requirements of the Air Toxics “Hot Spots” Program (Section 44360 *et seq.* of the Health and Safety Code). Ammonia is listed under the “Hot Spots” Program, and therefore, sources are required to report the quantity of ammonia they routinely release into the air. Gas turbines using selective catalytic reduction typically have been limited to 10 ppmvd at 15 percent oxygen ammonia slip; however levels as low as 2 ppmvd at 15 percent oxygen have been proposed and guaranteed by control vendors. Ammonia slip should be limited to at least the extent that the risk from ammonia emissions is within acceptable risk exposure levels.

ii. Regulation as a $PM_{2.5}$ Precursor

Ambient particulate matter less than 2.5 microns ($PM_{2.5}$) is composed of a mixture of particles directly emitted into the air and particles formed in air from the chemical transformation of gaseous pollutants (secondary particles). Principle types of secondary particles are ammonium sulfate and ammonium nitrate formed in air from gaseous emissions of sulfur oxides and NO_X, reacting with ammonia. Studies conducted in the South Coast Air Basin by Glen Cass of Caltech have indicated that ammonia is a primary component in secondary particulate matter. As a result, districts should consider the impact of ammonia slip on meeting and maintaining PM_{10} and $PM_{2.5}$ standards. Where a significant impact is identified, districts should revise their respective new source review rules to regulate ammonia as a precursor to both PM_{10} and $PM_{2.5}$.

2. SCONOx

The SCONOx system, developed by Goal Line Environmental Technologies, uses a catalyst to remove NO_X emissions by oxidizing NO to NO_2. The NO_X is absorbed onto the catalytic surface using a potassium carbonate (K_2CO_3) absorber coating. The potassium carbonate coating reacts with NO_2 to form potassium nitrites and nitrates which are deposited onto the catalyst surface. SCONOx does not use ammonia; therefore there are no ammonia emissions from this catalyst system. The reactions are shown below.

$$NO + \frac{1}{2} O_2 \rightarrow NO_2$$
$$2NO_2 + K_2CO_3 \rightarrow CO_2 + KNO_2 + KNO_3$$

The optimal temperature window for operation of the SCONOx catalyst is from 280 to 700 °F. Therefore, the catalyst is not applicable to simple-cycle configurations unless heat is recovered from the exhaust gas (see discussion in next section). Operating data from Federal Cogeneration in Los Angeles County, California, indicates SCONOx can achieve an emission level of 2.0 ppmvd NO_X at 15 percent oxygen (approximately 98.6 percent control).

When all of the potassium carbonate absorber coating has been converted to nitrogen compounds, NO_X can no longer be absorbed and the catalyst must be regenerated. Regeneration is accomplished by passing a dilute hydrogen reducing gas across the surface of the catalyst in the absence of oxygen. Hydrogen in the gas reacts with the nitrites and nitrates to form water and molecular nitrogen. Carbon dioxide in the gas reacts with the potassium nitrite and nitrates to form potassium carbonate, which is the absorbing surface coating on the catalyst.

$$KNO_2 + KNO_3 + 4H_2 + CO_2 \rightarrow K_2CO_3 + 4H_2O_{(g)} + N_2$$

The regeneration gas is produced by reacting natural gas with oxygen from ambient air. A gas generator uses a two-stage process to produce hydrogen and carbon dioxide. In the first stage, natural gas and air are reacted across a partial oxidation catalyst to form carbon monoxide and hydrogen. Steam is added to the mixture and then passed across a low temperature shift catalyst, forming carbon dioxide and more hydrogen. The mixture is diluted to under 4 percent hydrogen using steam.

The SCONOx catalyst is designed to be installed downstream of the gas turbine after the HRSG; whereas the selective catalytic reduction catalyst is installed within the HRSG in combined-cycle and cogeneration power plant configurations. Therefore, SCONOx may be a good option for retrofits of combined-cycle and cogeneration power plants because the catalyst can be added at the back of the HRSG without the major modification to the HRSG that would be required for selective catalytic reduction.

3. Exhaust Temperature Considerations

The efficiency of some NO_X controls is limited by temperature. This is especially true of catalytic controls. Catalytic control efficiencies may be reduced at hot or cold temperatures. For example, hot temperatures associated with uncooled exhaust may cause sintering of a catalyst. Conversely, low temperatures can result in higher NO_X emissions due to the fact that catalysts normally require a minimum temperature before they become chemically active.

Flue gas temperatures associated with simple-cycle gas turbines are generally higher than those of gas turbines used in combined-cycle and cogeneration operations. Simple-cycle gas turbines can have exhaust temperatures ranging up to and around 1100 °F, which vary only slightly from the gas turbine to the stack. With combined-cycle and cogeneration gas turbines, exhaust heat is removed with a HRSG, resulting in a decrease in flue gas temperatures (e.g., 1050 °F) from the gas turbine to the stack (e.g., 350 °F). Catalysts used for selective catalytic reduction are not as efficient in controlling NO_X at the higher temperatures associated with the uncooled exhaust of simple-cycle gas turbines. As a result, gas turbine emissions from combined-cycle and cogeneration operations can be controlled with more efficiency.

Staff is aware that, in general, aeroderived gas turbines have lower exhaust temperatures than industrial frame gas turbines, which has implications toward simple-cycle power plant configurations. For example, General Electric LM-series aeroderived gas turbines have exhaust temperatures ranging from approximately 752 to 974 °F. General Electric industrial-frame series gas turbines have exhaust temperatures ranging from approximately 909 to 1129 °F.[2] Therefore, it appears that where aeroderived gas turbines are proposed for simple-cycle power plants, high temperature catalytic control systems are feasible options and should perform at a control efficiency level near that of catalysts used in combined-cycle and cogeneration power plants. However, where industrial frame gas turbines are applied in simple-cycle power plants, the high exhaust temperatures approaching 1100 °F may require case-by-case evaluation regarding the feasiblity of NO_X control through selective catalytic reduction. Recognizing that catalysts must be restructured to deal with high temperatures, more operational problems may be encountered in consistently achieving the required emission levels due to the deactivation of the catalyst.

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[2] Gas Turbine World 1997 Handbook, Volume 18.

E. Current SIP Control Measures

There are several State Implementation Plan (SIP) control measures that have been applied to the control of NO_X emissions from gas turbines. The most stringent of these control measures has been adopted in California by the South Coast Air Quality Management District (SCAQMD) with NO_X emission standards based on size, annual operating hours, and control systems employed. The most stringent NO_X requirements are as follows: 25 parts per million by volume dry (ppmvd) at 15 percent oxygen averaged over 15 consecutive minutes for gas turbines from 0.3 to under 2.9 MW, 9 ppmvd at 15 percent oxygen averaged over 15 consecutive minutes for gas turbines of at least 2.9 MW but less than 10 MW, and 9 ppmvd at 15 percent oxygen averaged over 15 consecutive minutes for gas turbines of at least 10 MW employing selective catalytic reduction.[3] The control measure provides exemptions from the NO_X standards for certain units.[4] These SIP control measures have been adopted to comply with air quality goals of the California Clean Air Act of 1988 and meet a level of stringency referred to as Best Available Retrofit Control Technology (BARCT). BARCT is slightly more stringent than similar control measures required for the Federal Clean Air Act, which are referred to as Reasonably Available Control Technology (RACT). California district stationary gas turbine rules are available on the ARB's website at www.arb.ca.gov/html/drdb.htm.

F. Control Techniques Required as BACT

Tables C-1 and C-2 list the most stringent NO_X emission controls required as BACT that staff could locate for gas turbines of at least 20 MW fired on natural gas and used in simple-cycle, combined-cycle, and cogeneration power plant configurations.

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[3] SCAQMD rule provides for adjustment of emission limits based on the demonstrated percent efficiency of the gas turbine unit. These numbers are based on a minimum 25% efficiency.

[4] Exemptions are generally provided for laboratory units, units used only for firefighting or flood control, emergency standby units, units under 4 MW with limited annual hours of operation, and during startup and shutdown. Exemptions do not preempt the units from all rule requirements. The exemptions are primarily intended to indicate exemptions from emission limit requirements.

Table C-1: NO_X Emission Controls Required for Simple-Cycle Power Plant Gas Turbines				
Facility and Gas Turbine Description	Permitting	Method of NO_X Control	Emission Limits	Ammonia Slip Limit
Carson Energy 450 MMBtu/hr General Electric LM6000 gas turbine generator set producing 42 MW. Unit can co-fire with digester gas. Information provided applies to natural gas.	A/C: 11013 Issued: 7/23/93 P/O: 12830 Startup: 1995	Water injection + selective catalytic reduction	5 ppmvd @ 15% O_2 and 7.33 lb/hr (3-hr average) and 175.8 lb/day	20 ppmvd @ 15% O_2
Sacramento Cogeneration Authority (Proctor & Gamble) 421.4 MMBtu/hr General Electric LM6000 gas turbine generator set producing 25.24 MW	A/C: 11436 Issued: 8/19/94 Startup: not built yet	Water injection + selective catalytic reduction	5 ppmvd @ 15% O_2 (3-hr average)	20 ppmvd @ 15% O_2
Carolina Power & Light Four 1,907.6 General Electric 7231 FA gas turbine generator sets	A/C: 1812R18 Issued: 7/31/98 Startup: not built yet	Water injection	25 ppmvd @ 15% O_2 and 158 lb/hr and 0.084 lb/MMBrtu	Not applicable
Northern California Power Agency 325 MMBtu/hr General Electric MS 5001P "Frame 5" gas turbine generator set producing 25.24 MW	A/C: N-583-1-2 Issued: 10/2/97 P/O: N-583-1-2 Issued: 3/23/98	Water injection	42 ppmvd @ 15% O_2	Not applicable

Table C-2: NO_X Emission Controls Required for Combined-Cycle and Cogeneration Gas Turbines				
Facility and Gas Turbine Description	Permitting	Method of NO_X Control	Emission Limits	Ammonia Slip Limit
Sutter Power Plant Two 1,900 MMBtu/hr Westinghouse 501F gas turbines with two 170 MMBtu/hr auxiliary-fired HRSG producing 170 MW each and steam turbine producing 160 MW	CEC Docket: 97-AFC-2 Issued: 4/14/99 Startup: not built yet	Dry low-NO_X combustors + selective catalytic reduction	2.5 ppmvd @ 15% O_2 (1-hr average)	10 ppmvd @ 15% O_2
Sacramento Power Authority	A/C: 11456	Water injection	3 ppmvd @	10 ppmvd @

Table C-2: NO_X Emission Controls Required for Combined-Cycle and Cogeneration Gas Turbines				
Facility and Gas Turbine Description	Permitting	Method of NO_X Control	Emission Limits	Ammonia Slip Limit
(Campbell Soup) 1,257 MMBtu/hr Siemens V84.2 gas turbines with 200 MMBtu/hr auxiliary-fired HRSG producing 102 MW and 55 MW steam turbine	Issued: 8/19/94 P/O: 13629 Startup: 1997	+ selective catalytic reduction	15% O_2 (3-hr average)	15% O_2
Brooklyn Navy Yard Cogeneration Two 1,503 MMBtu/hr Siemens V84.2 gas turbines with HRSG producing 121 MW each and two 40 MW steam turbines	A/C: 2-6101-00185 Issued: 6/6/95 P/O: 2-6101-00185 Issued: 11/12/97	Dry low-NO_X combustors + selective catalytic reduction	3.5 ppmvd @ 15% O_2 (1-hr average)	10.0 ppmvd @ 15% O_2
Modesto Irrigation District 460 MMBtu/hr General Electric LM5000 PD gas turbine with HRSG producing 49.9 MW	A/C: N-3233-1-0 Issued: 3/16/94 P/O: N-3233-1-0 Issued: 7/21/95	Steam injection + selective catalytic reduction	3.5 ppmvd @ 15% O_2 (3-hr average)	25.0 ppmvd @ 15% O_2
Bear Mountain Limited G.T.E. cogeneration system including Stewart & Stevenson General Electric LM5000 gas turbine and HRSG producing 48 MW	A/C: S-2049-1-2 Issued: 8/19/94 P/O: S-2049-1-2 Issued: 10/4/95	Steam injection + selective catalytic reduction	3.6 ppmvd @ 15% O_2 (3-hr average)	20 ppmvd @ 15% O_2
Hermiston Generating Company Two 1,696 MMBtu/hr General Electric Frame 7FA gas turbines with HRSG (no duct burners)	A/C: 30-0113 Issued: 7/7/94 P/O: 30-0113 Startup: 3/28/96	Selective catalytic reduction	4.5 ppmvd @ 15% O_2	Not available
Portland General Electric Company Two 1,720 MMBtu/hr General Electric Frame 7FA gas turbine generator sets with HRSG.	A/C: 25-0031 Issued: 5/31/94 P/O: 25-0031 Startup: 11/1/95	Dry low-NO_X combustors + selective catalytic reduction	4.5 ppmvd @ 15% O_2 (24-hr average)	Not available
Crockett Cogeneration 1,935 MMBtu/hr General Electric PG7221 (Frame 7FA) gas turbine with 349 MMBtu/hr auxiliary-fired HRSG producing 240 MW	A/C: S-201 Issued: 10/5/93 P/O: S-201 Issued: 12/19/96	Low-NO_X duct burner and Dry low-NO_X combustors + selective catalytic reduction	5 ppmvd @ 15% O_2 (3-hr average)	10 ppmvd @ 15% O_2

Table C-2: NO_X Emission Controls Required for Combined-Cycle and Cogeneration Gas Turbines				
Facility and Gas Turbine Description	Permitting	Method of NO_X Control	Emission Limits	Ammonia Slip Limit
Carson Energy 450 MMBtu/hr General Electric LM6000 gas turbine with 99.8 MMBtu/hr auxiliary-fired HRSG producing 42 MW	A/C: 11012 Issued: 7/23/93 P/O: 12829 Startup: 1995	Water injection + selective catalytic reduction	5 ppmvd @ 15% O_2 (3-hr average)	20 ppmvd @ 15% O_2

G. Emission Levels Achieved in Practice

Tables C-3 and C-4 list the most stringent NO_X emission levels staff could locate which were achieved by simple-cycle, combined-cycle, and cogeneration power plant gas turbines while combusting natural gas.

Table C-3: NO_X Emission Source Test Results for Simple-Cycle Gas Turbines		
Facility and Gas Turbine Description	Method of NO_X Control	Measured Emissions
Carson Energy 450 MMBtu/hr General Electric LM6000 gas turbine producing 42 MW. Unit can co-fire with digester gas. Information provided applies to natural gas.	Water injection + selective catalytic reduction	4.72 ppmvd @ 15% O_2 in Sep-Oct 1995
		3.95 ppmvd @ 15% O_2 in Nov 1996
		3.96 ppmvd @ 15% O_2 in Nov 1997-Jan 1998
Northern California Power Agency 325 MMBtu/hr General Electric Frame 5 gas turbine producing 25.24 MW	Water injection	37.58 ppmvd @ 15% O_2 in May 1997

Table C-4: NO_X Emission Source Test Results for Combined-Cycle and Cogeneration Gas Turbines		
Facility and Gas Turbine Description	Method of NO_X Control	Measured Emissions
Brooklyn Navy Yard Cogeneration	Dry low-NO_X combustors +	2.2 ppmvd and 1.8 ppmvd @ 15% O_2

Table C-4: NO_X Emission Source Test Results for Combined-Cycle and Cogeneration Gas Turbines

Facility and Gas Turbine Description	Method of NO_X Control	Measured Emissions
Two 1,503 MMBtu/hr Siemens V84.2 gas turbines with HRSG producing 121 MW each and two 40 MW steam turbines	selective catalytic reduction	in 1996 startup source test
Crockett Cogeneration 1,935 MMBtu/hr General Electric PG7221 (Frame 7FA) gas turbine with 349 MMBtu/hr auxiliary-fired HRSG producing 240 MW	Low-NO_X duct burner and Dry low-NO_X combustors + selective catalytic reduction	4.31 ppmvd @ 15% O_2 in Jun 1997
		3.27 ppmvd @ 15% O_2 in Jun 1998
Federal Cold Storage Cogeneration 222.2 MMBtu/hr General Electric LM2500-M-2 gas turbine and steam turbine producing 32 MW	Water injection + SCONOx catalyst	2.0 ppmvd @ 15% O_2 with 6 months (Jun-Dec 1997) CEMs data analysis
Modesto Irrigation District 460 MMBtu/hr General Electric LM5000 PD gas turbine with HRSG producing 49.9 MW	Steam injection + selective catalytic reduction	2.25 ppmvd @ 15% O_2 in 1996
		2.97 ppmvd @ 15% O_2 in 1997
		2.5 ppmvd @ 15% O in 1998
Sacramento Power Authority (Campbell Soup) 1,257 MMBtu/hr Siemens V84.2 gas turbine with 200 MMBtu/hr auxiliary-fired HRSG producing 102 MW and 55 MW steam turbine	Water injection + selective catalytic reduction	2.47 ppmvd @ 15% O in Oct 1997
		2.39 ppmvd @ 15% O_2 in Oct 1998

H. More Stringent Control Techniques

1. Technologically Feasible Controls

a. Lower NO_X Emission Levels Using Tandem Approach

There are three basic types of NO_X emission controls employed to gas turbines: wet controls using water or steam injection to reduce combustion temperatures for NO_X control, dry controls using advanced combustor design to suppress NO_X formation, and post-combustion controls to reduce NO_X formed in the turbine. While each type of control results in a particular level of NO_X emissions, the potential for reducing NO_X emissions down to single-digit values and fractions thereof can be achieved by applying a tandem approach, using controls in combination to reduce NO_X. Common NO_X control combinations currently in use include water or steam injection with selective catalytic reduction, dry low-NO_X combustors with selective catalytic reduction, and water injection with SCONOx. Where present, there is also the potential to control NO_X from duct burners through burner combustion controls. The combination of duct burner, gas turbine combustion, and add-on controls has the potential to reduce NO_X emissions to levels more stringent than what has currently been achieved in practice.

b. Scale-up and Lower Emission Levels with SCONOx

Deregulation of the electric utility industry in the New England area of the United States has, like California, brought about an increase in the number of proposed power plant projects. Fifteen such projects are currently proposed in the Commonwealth of Massachusetts. The Massachusetts Department of Environmental Protection (MDEP), in a January 29, 1999, memorandum from David Struhs, recognizes that technologies are commercially available that can achieve a BACT/LAER emission level of 2.0 ppmvd NO_X at 15 percent oxygen. Also, due to MDEP approval of a 5 MW combined-cycle power plant at the Genetics Institute in Andover, Massachusetts, using a dry low-NO_X combustor with SCONOx, MDEP will require a zero ammonia emission rate for all power generation units 50 MW or less. Eventually, MDEP's goal is to establish a zero ammonia emission rate for power plants generating 50 MW or more.

The basis for requiring zero ammonia in addition to the 2.0 ppmvd NO_X level is contained in the Northeast States for Coordinated Air Use Management (NESCAUM) BACT Guideline (June 1991). The guideline states that "where approximately the same degree of emission reduction can be achieved by different technologies, preference should be given to the technology that achieves the reduction with the greatest degree of pollution prevention."

Due to liability issues associated with merchant mode operation, power plant project proponents are demanding that the power plant gas turbine supplier bear liquidated damages if a power plant fails to attain its promised level of availability. In order to justify liability assumption for a control system's potential impact on plant performance, a high degree of confidence in the technology is required. Without an extensive track record of performance on a large gas turbine, ABB Environmental Systems Division (SCONOx licensee for systems over 100 MW) is reluctant to guarantee that the technology will meet necessary performance requirements. MDEP has addressed this concern through project-specific permit conditions which allow a "soft landing" approach. This soft landing allows the permit to be written such that time for testing and evaluation of the BACT/LAER control technology is allowed and there is an opportunity to revise permit conditions and substitute technology if it is demonstrated that the BACT/LAER standard cannot be achieved. A November 11, 1998, letter from Jan Kreminski of ABB Environmental Systems Division to Ed Braczyk of MDEP, states that ABB will offer SCONOx for sale subject to the soft landing as part of ABB's turnkey power plant projects. However, the letter also states that ABB is moving toward performing the necessary testing for scale-up with the expectation of meeting emission levels and being able to offer SCONOx without the soft landing.

More recently, a February 18, 1999, letter from Robert Danziger of Sunlaw Energy Corporation to Dr. Barry Wallerstein of SCAQMD proposes a NO_X emission rate of 1 ppmvd at 15 percent oxygen averaged over 1 hour for a 840 MW combined-cycle gas-fired power plant in Los Angeles County, California. The project will include three ABB GT KA 24-1 gas turbines. The NO_X emission level will be achieved using SCONOx. There are no ammonia emissions from the SCONOx technology. This project represents a refining of the SCONOx control technology which is already recognized as achieved in practice at 2.0 ppmvd at 15 percent oxygen. The Application for Certification (AFC) is tentatively scheduled to be filed with the California Energy Commission in September 1999.

c. Lower Emission Levels with Selective Catalytic Reduction

In line with the push toward zero ammonia emissions, power plant projects in Massachusetts have proposed very low NO_X and ammonia slip limits using selective catalytic reduction. Two power plant projects have received "conditional" approval of their air quality plans from the Massachusetts Department of Environmental Protection. The projects were conditionally approved because specific information on the emission control systems (specific manufacturer, model number, and operational parameters), construction plans, certain plant operational and maintenance procedures, and specific continuous emission monitors (CEMs) information had not been finalized at the time of issuance.

The first project is ANP Blackstone in Blackstone, Massachusetts. ANP Blackstone is a 580 MW combined-cycle power plant. The power plant will consist of two parallel power trains, each including one 180 MW (210 MW with steam augmentation) ABB GT-24 gas turbine. Emission limits are provided for four different loads. The proposed limits are 2.0 ppmvd NO_X at 15 percent oxygen and 2.0 ppmvd ammonia at 15 percent oxygen averaged over 1 hour. The limit increases to 3.5 ppmvd NO_X at 15 percent oxygen and 2.0 ppmvd ammonia at 15 percent oxygen averaged over 1 hour when steam injection for power augmentation is used. Overall annual NO_X emissions are limited to 2.3 ppmvd at 15 percent oxygen over a 12-month rolling average.

The second project is ANP Bellingham in Bellingham, Massachusetts. ANP Bellingham is a 580 MW combined-cycle power plant. The power plant will consist of two parallel power trains, each including one 180 MW (210 MW with steam augmentation) ABB GT-24 gas turbine. Emission limits are provided for four different loads. The proposed limits are 2.0 ppmvd NO_X at 15 percent oxygen and 2.0 ppmvd ammonia at 15 percent oxygen averaged over 1 hour. The limit increases to 3.5 ppmvd NO_X at 15 percent oxygen and 2.0 ppmvd ammonia at 15 percent oxygen averaged over 1 hour when steam injection for power augmentation is used. Overall annual NO_X emissions are limited to 2.3 ppmvd at 15 percent oxygen over a 12-month rolling average.

Another project, 360 MW Island End Cogeneration, in Massachusetts, is still in the draft stage and has not been submitted for pubic review. It is expected that the proposed emission levels will be 2.0 ppmvd NO_X at 15 percent oxygen and 2.0 ppmvd ammonia at 15 percent oxygen averaged over 1 hour using selective catalytic reduction.

2. Developing Control Technologies

a. XONON

XONON is a NO_X control mechanism (and also results in low-level CO and VOC emissions) accomplished through the combustion process using a catalyst to limit the temperature in the combustor below the temperature where NO_X is formed. The XONON combustion system consists of four sections: 1) the preburner, for start-up, acceleration of the turbine engine, and adjusting catalyst inlet temperature if needed; 2) the fuel injection and fuel-air mixing system, which achieves a uniform fuel-air mixture to the catalyst; 3) the flameless catalyst module, where a portion of the fuel is combusted flamelessly; and 4) the burnout zone, where the remainder of the fuel is combusted.

There is currently one field installation of the XONON technology at a municipal power company, Silicon Valley Power, in Santa Clara, California, being used as a “test bed” for engineering studies on the XONON system. Exhaust gas from the turbine is ducted to a vertical stack equipped with sampling ports and CEMs. Emission test data have indicated NO_X levels from 1.33 to 4.04 ppmvd at 15 percent oxygen over a range of turbine loads. This facility consists of a 1.5 MW simple-cycle Kawasaki M1A-13A gas turbine. There is not yet sufficient operating data to deem this level of control achieved in practice for the operation. Catalytica Combustion Systems (manufacturer of XONON) has a collaborative commercialization agreement with General Electric Power Systems, committing to the development of XONON. General Electric has expressed its desire to work with Catalytica to adapt XONON to its Frame E-class and F-class turbines in order to demonstrate the technology on a larger scale and commence marketing.

b. Low-NO_X Duct Burner

Coen Company submitted a proposal in February 1999 to ARB's Innovative Clean Air Technology (ICAT) Program to develop and demonstrate a low-NO_X duct burner for cogeneration that would reduce NO_X emissions below 5 ppmvd at 15 percent oxygen, in order to match the NO_X emissions performance of XONON. The project will utilize advanced fuel and air mixing strategies, stability enhancements, and control system design to achieve the target NO_X levels. Use of the new low-NO_X duct burner technology in conjunction with XONON has the potential to match BACT emission levels without the need for add-on control systems such as selective catalytic reduction. Projected date of commercial availability is 2001 to 2002.

I. Discussion and Recommendations

1. Simple-Cycle Gas Turbines

The most stringent NO_X BACT for a simple-cycle gas turbine was required in the preconstruction permit for Carson Energy Group in Sacramento County, California, at 5 ppmvd NO_X at 15 percent oxygen averaged over 3 hours. The determination was made for a nominally rated 42 MW power plant consisting of a 450 MMBtu/hr General Electric LM6000 simple-cycle gas turbine equipped with an oxidation catalyst. The gas turbine has been in operation since 1995. Since startup, the gas turbine has demonstrated compliance with the NO_X emission limit in three consecutive years of source testing. NO_X emissions varied from 3.957 to 4.72 ppmvd NO_X at 15 percent oxygen. Considering that the Carson Energy Group represents the most stringent NO_X BACT which has been achieved in practice, staff recommends a BACT level for NO_X emissions from simple-cycle gas turbines of 5 ppmvd at 15 percent oxygen averaged over 3 hours.

2. Combined-Cycle and Cogeneration Gas Turbines

The most stringent NO_X BACT limit for an operating combined-cycle/cogeneration gas turbine is 3 ppmvd at 15 percent oxygen averaged over 3 hours. This emission level was achieved on a 102 MW combined-cycle Siemens V84.2 gas turbine at Sacramento Power Authority (Campbell Soup) in Sacramento County, California, with dry low-NO_X burner and selective catalytic reduction. This unit has been operating since October 1997. Two consecutive annual source tests at the power plant recorded emission levels of 2.39 and 2.47 ppmvd NO_X at 15 percent oxygen.

The most stringent BACT limit for a combined-cycle/cogeneration gas turbine was required in the preconstruction permit issued for the Sutter Power Plant near Yuba City, California. This determination was for a Westinghouse 501F gas turbine nominally rated at 170 MW. It requires 2.5 ppmvd NO_X at 15 percent oxygen averaged over 1-hour. This low emission level will be achieved using dry low-NO_X burners and selective catalytic reduction.

Emission levels of 2.0 ppmvd NO_X at 15 percent oxygen using 15 minute averages measured with CEMs were achieved at Federal Cogeneration in Los Angeles, California, utilizing water injection in conjunction with SCONOx. This facility consists of a 32 MW combined-cycle General Electric LM2500 gas turbine. Initially, six months of CEMs data from June to December 1997 were examined by both the United States Environmental Protection Agency (U.S. EPA) and the South Coast Air Quality Management District (SCAQMD). Considering the circumstances, U.S. EPA subsequently deemed 2.0 ppmvd at 15 percent oxygen with a 3-hour averaging time as demonstrated in practice. This finding was presented in a March 23, 1998, letter from Matt Haber of U.S. EPA to Robert Danziger of Goal Line Environmental Technologies. U.S. EPA acknowledged that future combined-cycle gas turbine projects subject to LAER must recognize the 2.0 ppmvd limit. U.S. EPA also acknowledged that future combined-cycle gas turbine projects subject to BACT as required in Part C of the federal Clean Air Act should consider the 2.0 ppmvd limit when performing their top-down BACT analysis. The SCAQMD subsequently determined BACT as 2.5 ppmvd at 15 percent oxygen with 1-hour averaging[5]. U.S. EPA correspondence of June 10, 1998, subsequent to this determination recognized 2.0 ppmvd and 2.5 ppmvd at 15 percent oxygen with 3 and 1-hour averaging times, respectively, as levels that would represent BACT.

In light of the above findings, staff recommends a BACT level for NO_X emissions from combined-cycle and cogeneration gas turbines of 2.5 ppmvd at 15 percent oxygen averaged over 1 hour. In addition to the Sutter Power Plant, this NO_X BACT level is being proposed for other combined-cycle and cogeneration power plant projects currently in review through the California Energy Commission's siting process. These power plants include: High Desert Power Plant, La Paloma Generating Company, Sunrise Cogeneration, Delta Energy Center, and Metcalf Energy Center. Use of dry low-NO_X combustors in conjunction with selective catalytic reduction to meet the NO_X emission level was confirmed for High Desert Power Plant, La Paloma Generating Company, and Sunrise Cogeneration.

III. POTENTIAL METHODS OF CO EMISSION CONTROL

A. CO Formation Mechanism

Proper mixing of air and fuel is important for complete combustion to occur. When a hydrocarbon fuel, such as natural gas, burns completely, the oxygen in the air combines with the hydrogen to form water (H_2O) and with the carbon to form carbon dioxide (CO_2). If the combustion is incomplete, some of the carbon atoms combine with only one oxygen atom to form CO. Because oxygen is not ideally available in stoichiometric amounts, the carbon in the gas is not oxidized completely to CO_2 and CO is formed.

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[5] NO_X emission averaging time is not included in the BACT summary; however SCAQMD staff report clarifies the averaging time as 1 hour.

B. Combustion CO Controls

Generally, maximizing the time, temperature, and turbulence, provides for more efficient combustion and reduced CO emissions. Residence time is the amount of time for the combustion gases to flow through the combustor. The residence time can be increased by augmenting the length of the combustor. The longer the residence time, however, the more NO_X emissions are produced due to exposure of the combustion gases to high temperatures for increased periods of time.

3. Flue-Gas CO Controls

1. Oxidation Catalyst

In catalytic oxidation, a catalyst is used to oxidize CO at lower temperatures. The addition of a catalyst to the basic thermal oxidation process accelerates the rate of oxidation by adsorbing oxygen from the air stream and CO in the waste stream onto the catalyst surface to react to form CO_2 and H_2O. Typical control efficiencies from an oxidation catalyst are from 80 to 90 percent.

2. SCONOx

In addition to NO_X, the SCONOx catalyst system also removes CO emissions by oxidizing CO to CO_2. The reaction is shown below.

$$CO + \frac{1}{2} O2 \rightarrow CO2$$

A more lengthy description of the SCONOx technology is described in the previous discussion of flue-gas NO_X controls.

D. Exhaust Temperature Considerations

As was iterated in the discussion of NO_X emission controls, the efficiency of some CO control technologies is limited by temperature. This is especially true of catalytic controls. Catalytic control efficiencies may be reduced at hot or cold temperatures. For example, hot temperatures associated with uncooled exhaust may cause sintering of a catalyst. Conversely, low temperatures can result in higher CO emissions due to the fact that catalysts normally require a minimum temperature before they become chemically active.

5. Current SIP Control Measures

Historically, two forms of CO emission controls have been used on gas turbines. Combustion controls were used by the mid-1980s to achieve emission levels down to 10 ppmvd at 15 percent oxygen. In the late 1980's, oxidation catalysts were used on larger gas turbine cogeneration units. Oxidation catalysts can achieve 80 to 90 percent control of CO emissions. To date, use of oxidation catalysts have been largely limited to cogeneration and combined-cycle power plants. Although high temperature oxidation catalysts are available, sintering problems can appear at flue gas temperatures above 1050 °F. Simple-cycle gas turbines with lower flue gas temperatures have been controlled with high temperature oxidation catalysts.

Currently, only two areas are designated nonattainment for the California CO ambient air quality standards: Los Angeles County and the city of Calexico in Imperial County. The only area of California designated nonattainment for the national CO ambient air quality standards is the South Coast Air Basin.[6] In both cases, CO violations arise primarily from concentrated motor vehicle emissions. As a result, districts have not historically instituted control measures that have applied specifically to the regulation of CO emissions from gas turbines. The only California district with a CO emissions limit for gas turbines is the San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD). SJVUAPCD Rule 4703 limits CO emissions from gas turbines to 25 to 250 ppmvd at 15 percent oxygen averaged over 3 hours, depending on turbine design and use. The control measure is applicable to stationary gas turbines of at least 0.3 MW.

F. Control Techniques Required as BACT

Tables C-5 and C-6 list the most stringent CO emission controls required as BACT that staff could locate for gas turbines of at least 20 MW fired on natural gas and used in simple-cycle, combined-cycle, and cogeneration power plant configurations.

Table C-5: CO Emission Controls Required for Simple-Cycle Gas Turbines

Facility and Gas Turbine Description	Permitting	Method of CO Control	Emission Limits	Approx. Emission Concentration in ppmvd at 15% O_2
Carson Energy	A/C: 11013 Issued: 7/23/93	Oxidation	5.93 lb/hr (3-hr average)	5.97

[6]California Air Resources Board "The 1999 California Almanac of Emissions & Air Quality," pp. 24-25.

Table C-5: CO Emission Controls Required for Simple-Cycle Gas Turbines				
Facility and Gas Turbine Description	Permitting	Method of CO Control	Emission Limits	Approx. Emission Concentration in ppmvd at 15% O_2
450 MMBtu/hr General Electric LM6000 gas turbine producing 42 MW. Unit can co-fire with digester gas. Information provided applies to natural gas.	P/O: 12830 Startup: 1995	catalyst	and 142.3 lb/day	
Carolina Power & Light Four 1,907.6 General Electric 7231 FA gas turbines	A/C: 1812R18 Issued: 7/31/98 Startup: not built yet	Combustion control	80 lb/hr and 0.042 lb/MMBrtu	19
Northern California Power Agency 325 MMBtu/hr General Electric Frame 5 gas turbine producing 25.24 MW	A/C: N-583-1-2 Issued: 10/2/97 P/O: N-583-1-2 Issued: 3/23/98	Good combustion practices	0.0677 lb/MMBtu	28.6

Table C-6: CO Emission Controls Required for Combined-Cycle and Cogeneration Gas Turbines				
Facility and Gas Turbine Description	Permitting	Method of CO Control	Emission Limits	Approx. Emission Concentration in ppmvd at 15% O_2
Newark Bay Cogeneration Partnership Two 640 MMBtu/hr Westinghouse CW251/B-12 gas turbines	A/C: 01-92-5231 to 01-92-5261 Issued: 6/9/93 P/O: 01-92-5231 to 01-92-5261 Startup: 8/1/93	Oxidation catalyst	1.8 ppmvd @ 15% O_2 (1-hr average)	1.8
Sacramento Power Authority (Campbell Soup) 1,257 MMBtu/hr Siemens V84.2 gas turbine with 200 MMBtu/hr auxiliary-fired HRSG producing 102 MW and 55 MW steam turbine	A/C: 11456 Issued: 8/19/94 P/O: 13629 Startup: 1997	Oxidation catalyst	CTG: 8.11 lb/hr (3-hr average)	2.92
			CTG + DB: 9.63 lb/hr (3-hr average)	2.99
Sutter Power Plant	CEC Docket: 97-	Oxidation	4.0 ppmvd @	4.0

Table C-6: CO Emission Controls Required for Combined-Cycle and Cogeneration Gas Turbines				
Facility and Gas Turbine Description	Permitting	Method of CO Control	Emission Limits	Approx. Emission Concentration in ppmvd at 15% O_2
Two 1,900 MMBtu/hr Westinghouse 501F gas turbines with two 170 MMBtu/hr auxiliary-fired HRSG producing 170 MW each and driving a common 160 MW steam turbine	AFC-2 Issued: 4/14/99 Startup: not built yet	catalyst	15% O_2 (24-hr average)	
Crockett Cogeneration 1,935 MMBtu/hr General Electric PG7221 (Frame 7FA) gas turbine with 349 MMBtu/hr auxiliary-fired HRSG producing 240 MW	A/C: S-201 Issued: 10/5/93 P/O: S-201 Issued: 12/19/96	Engelhard Oxidation catalyst	5.9 ppmvd @ 15% O_2 (3-hr average)	5.9
La Paloma Generating Company Four 1,736 MMBtu/hr ABB GT-24 OTC gas turbines producing 172 MW each and four steam turbines producing 90 MW each	A/C: S-3412-1-0, S-3412-2-0, S-3412-3-0, S-3412-4-0 Issued: 5/26/99 Startup: not built yet	Oxidation catalyst	6 ppmvd @ 15% O_2 (3-hr average) at >73% load and 10 ppmvd @ 15% O_2 (3-hr average) at <73% load	6 (>73% load) 10 (<73% load)
Pittsburg District Energy Facility Two 1,929 MMBtu/hr General Electric Frame 7FA PG 7231 gas turbines with 83 MMBtu/hr auxiliary-fired HRSG producing 170 MW and 90 MW steam turbines	A/C: 18595 Issued: 6/10/99 (FDOC date) Startup: not built yet	Oxidation catalyst	6 ppmvd @ 15% O_2 (3-hr average)	6
Bear Mountain Limited G.T.E. cogeneration system including Stewart & Stevenson General Electric LM5000 gas turbine and HRSG producing 48 MW	A/C: S-2049-1-2 Issued: 8/19/94 P/O: S-2049-1-2 Issued: 10/4/95	Oxidation catalyst	10 ppmvd @ 15% O_2 (3-hr average) and 252.6 lb/day	10
Modesto Irrigation District 460 MMBtu/hr General Electric LM5000 PD gas turbine with HRSG producing 49.9 MW.	A/C: N-3233-1-0 Issued: 3/16/94 P/O: N-3233-1-0 Issued: 7/21/95	Oxidation catalyst	16.0 ppmvd @ 15% O_2 (3-hr average)	16

Table C-6: CO Emission Controls Required for Combined-Cycle and Cogeneration Gas Turbines				
Facility and Gas Turbine Description	Permitting	Method of CO Control	Emission Limits	Approx. Emission Concentration in ppmvd at 15% O_2
Carson Energy 450 MMBtu/hr General Electric LM6000 gas turbine with 99.8 MMBtu/hr auxiliary-fired HRSG producing 42 MW	A/C: 11012 Issued: 7/23/93 P/O: 12829 Startup: 1995	Good combustion practices	CTG: 5.93 lb/hr (3-hr average) and 142.3 lb/day	5.94
			CTG + DB: 40.0 lb/hr (3-hr average) and 547.0 lb/day	32.95

G. Emission Levels Achieved in Practice

Tables C-7 and C-8 list the most stringent CO emission levels staff could locate which were achieved by simple-cycle, combined-cycle, and cogeneration power plant gas turbines while combusting natural gas.

Table C-7: CO Emission Source Test Results for Simple-Cycle Gas Turbines			
Facility and Gas Turbine Description	Method of CO Control	Measured Emissions	Approx. Emission Concentration in ppmvd at 15% O_2
Carson Energy 450 MMBtu/hr General Electric LM6000 gas turbine producing 42 MW. Unit can co-fire with digester gas. Information provided applies to natural gas.	Oxidation catalyst	0.18 lb/hr in Sep-Oct 1995	0.16
		0.196 lb/hr in Nov 1996	0.18
		0.07 lb/hr in Nov 1997-Jan 1998	0.06
Northern California Power Agency 325 MMBtu/hr General Electric Frame 5 gas turbine producing 25.24 MW	Good combustion practices	1.04 ppmvd @ 15% O_2 in May 1997	1.04

Table C-8: CO Emission Source Test Results for Combined-Cycle and Cogeneration Gas Turbines			
Facility and Gas Turbine Description	Method of CO Control	Measured Emissions	Approx. Emission Concentration in ppmvd at 15% O_2
Brooklyn Navy Yard Cogeneration Two 1,503 MMBtu/hr Siemens V84.2 gas turbine with HRSG producing 121 MW each and two 40 MW steam turbines	W.R. Grace Oxidation catalyst	0.27 ppmvd and 1.1 ppmvd @ 15% O_2 in 1996	0.27 and 1.1
Crockett Cogeneration 1,935 MMBtu/hr General Electric PG7221 (Frame 7FA) gas turbine with 349 MMBtu/hr auxiliary-fired HRSG producing 240 MW	Engelhard Oxidation catalyst	1.11 ppmvd @ 15% O_2 in Jun 1997	1.11
		2.02 ppmvd @ 15% O_2 in Jun 1998	2.02
Modesto Irrigation District 460 MMBtu/hr General Electric LM5000 PD gas turbine with HRSG producing 49.9 MW	Oxidation catalyst	1.79 ppmvd @ 15% O_2 in 1996	1.79
		1.03 ppmvd @ 15% O_2 in 1997	1.03
		0.7 ppmvd @ 15% O_2 in 1998	0.7
Newark Bay Cogeneration Partnership Two 640 MMBtu/hr Westinghouse CW251/B-12 gas turbines	Oxidation catalyst	Both 0.1 ppmvd @ 15% O_2 in 1993	0.1
Sacramento Power Authority (Campbell Soup) 1,257 MMBtu/hr Siemens V84.2 gas turbine with 200 MMBtu/hr auxiliary-fired HRSG producing 102 MW and 55 MW steam turbine	Oxidation catalyst	CTG + DB: 0.50 lb/hr in Oct 1997	0.16
		CTG + DB: 1.89 lb/hr in Oct 1998	0.62

H. More Stringent Control Techniques

1. Technologically Feasible Controls

Source testing at Newark Bay Cogeneration Partnership resulted in compliance with a permitted CO emission limit of 1.8 ppmvd at 15 percent oxygen through use of an oxidation catalyst. The facility is a 136 MW cogeneration plant with two 617 MMBtu/hr natural gas-fired combustion turbines located in Newark, New Jersey, in a federal CO nonattainment area. Source testing is not required on an annual basis, however, so assessment as to whether the level has been demonstrated cannot be determined without review of CEMs data.

Goal Line Environmental Technologies claims SCONOx can achieve 2.0 ppmvd CO at 15 percent oxygen averaged over 1 hour. The basis for this claim is CEMs operating data from Federal Cogeneration in Los Angeles, California, which uses water injection in conjunction with SCONOx. This facility consists of a 32 MW combined-cycle General Electric LM2500 gas turbine. Staff was unable to verify this claim by the time of publication of this guidance document.

2. Developing Control Technologies

Staff is not aware of any new CO abatement technologies currently under development which are actively targeting the gas turbine market.

I. Effect of CO Oxidation Catalyst on PM_{10} Emissions

There has been some concern expressed in comments received by staff that oxidation catalysts can oxidize sulfur dioxide (SO_2) to sulfate. The proponents of this theory generally believe that such sulfate production provides a reason to reconsider the relative merits of oxidation catalysts for the purpose of controlling CO and VOC. So far, the conversion rate assumed and accepted in a recently approved project is the 10 percent conversion of fuel sulfur to sulfate assumed on the Sutter Power Plant. Other parties providing comments assert that there is no evidence of significant conversion of SO_2 to sulfate across the oxidation catalyst.

One commenter points out that there will be a general emission increase of all air pollutant emissions attributable to a marginal increase in fuel consumption required to overcome the extra back pressure from the oxidation catalyst. In addition, the commenter claims that an 80 percent conversion of SO_2 to sulfate will occur across the oxidation catalyst. Assuming a fuel consumption of 2,003 million British thermal units per hour (MMBtu/hr) of natural gas with a heating value of 23,141 Btu/lb and a sulfur content of 0.25 grains per standard cubic foot (gr/scf), the commenter's analysis indicates PM_{10} emissions are increased by 2.18 lb/hr (combined-cycle gas turbine units of this size may emit from 11.5 to 17 lb/hr). However, there was no discussion in the commenter's letter providing a basis for the 80 percent conversion rate. A follow-up discussion with the commenter indicated the 80 percent conversion was derived from a graph of

SO_2 oxidation versus temperature for an Engelhard Camet oxidation catalyst which had been provided by a contractor for the San Diego Gas and Electric South Bay repower project.[7]

Assertions are countered by the Engelhard Corporation, an oxidation catalyst manufacturer. In a June 1, 1999, letter from Engelhard, a graph was submitted showing SO_2 conversion to sulfur trioxide (SO_3) across an Engelhard Camet Oxidation Catalyst as a function of temperature. The graph was for lower space velocities than normally used on California gas turbines, resulting in a liberal estimate of the conversion rate. Engelhard argues that at 600 to 650 °F, there is very little oxidation of SO_2 to SO_3 (a maximum of 10 percent), which is a typical gas temperature where the catalyst is installed. Inspecting other data provided, temperatures may potentially range up to 1000 °F, where the conversion rate could range above 85 percent. But even so, the letter maintains the following:

> "For this small level of SO_3 to contribute to particulate matter in the stack, it will have to react with ammonia and condense. Condensation will only occur if the dew point of ammonia reaction products is above the exhaust temperature at the stack. The dew point of sulfate reaction products is about 120 °F. This is well below the temperature in the stack of a combined cycle power plant and very close to ambient conditions in many locations. Therefore, the oxidation of SO_2 to SO_3 will not form particulate matter that can be detected in the gas turbine exhaust."

Engelhard goes on to contend that source tests on units with oxidation catalysts show low particulate matter concentrations that are comparable to those without oxidation catalysts. Furthermore, Engelhard indicates lower ammonia slip rates (e.g., 2 ppmvd) will reduce sulfate formation. Although ammonia slip rates are normally limited to 10 ppmvd at 15 percent oxygen,

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[7]In addition to discussion on SO_2 to sulfate conversion across an oxidation catalyst, a 6.5 percent conversion efficiency of fuel sulfur to sulfate during combustion was provided, a value that was provided in 1993 by Black and Veatch based on good engineering judgement for a Westinghouse gas turbine with dry low-NO_X combustors. The commenter noted that this conversion rate will likely be specific to the combustor design. He also noted that the same contractor provided a 10 percent estimate of SO_2 to sulfate conversion across an SCR catalyst. Using this data along with the 80 percent conversion across the oxidation catalyst, the overall conversion is 83 percent, assuming the oxidation catalyst is upstream of the SCR unit.

actual slip rates are normally much less, especially when the catalyst is new or after being regenerated.

The sulfate matter was also addressed in detail in a June 2, 1999, letter from the California Unions for Reliable Energy (CURE). The letter argued the following:

1. There is no correlation between flue gas temperature and particulate matter emissions. Because SO_2 to SO_3 conversion rates across a catalyst increase across the operating range of oxidation catalysts, one would expect greater sulfate and PM emissions at higher temperatures. Using a two-tailed Student's t test on two sets of test results from gas turbines with catalysts operated at low and high temperatures, there was no statistical difference between the two groups.
2. There is no correlation between fuel sulfur content and particulate matter emissions. This argument was supported by the lack of difference between gas turbines burning natural gas with low and high sulfur contents.
3. There is no difference in particulate matter emissions with and without CO oxidation catalysts. This argument was supported by looking at two gas turbines at Carson Energy, one with and the other without an oxidation catalyst. A two-tailed Student's t test showed no statistically significant difference between source tests from the two different units, although the populations of source tests were small.
4. PM emissions are too low to be caused by SO_2 oxidation sulfate. If one was to assume that all SO_3 attributed to an oxidation catalyst were converted to sulfate, measured PM should be an order of magnitude higher. ARB staff was unable to verify calculations used to make this argument.
5. Exhaust gas particulate matter concentrations are comparable to inlet concentrations. The letter provided data indicating that inlet particulate matter concentration are similar to filterable PM stack emissions. ARB staff does not necessarily agree, however, that the particles entering and exiting the gas turbine are the same.

Furthermore, the letter noted that Engelhard's assertions regarding sulfate formation were supported by the scientific literature.[8] Altogether, these argument are convincing, especially since they are supported by measurements and measurement-based calculations. Staff are not aware of any other similar measurement data that could support arguments to the contrary.
From the perspective of staff, there is not enough evidence indicating any significant increase PM_{10} emission caused by oxidation catalysts.

J. Discussion and Recommendations

[8] S. Matsuda et al. 1982. Deposition of ammonium bisulfate in the selective catalytic reduction of nitrogen oxides with ammonia. Ind. Eng. Chem. Prod. Res. Dev., 21:48-52.

1. Simple-Cycle Gas Turbines

The most stringent CO BACT for a simple-cycle gas turbine was required in the preconstruction permit for Carson Energy Group in Sacramento County, California, at 5.93 lb/hour, averaged over 3 hours (equivalent to approximately 5.97 ppmvd CO at 15 percent oxygen). The determination was made for a 42 MW nominal power plant consisting of a 450 MMBtu/hr General Electric LM6000 simple-cycle gas turbine equipped with an oxidation catalyst. The gas turbine has been in operation since 1995. Since startup, the gas turbine has demonstrated compliance with the CO emission limit in three consecutive years of source testing. CO emissions varied from 0.07 to 0.29 lb/hr (0.06 to 0.26 ppmvd CO at 15 percent oxygen). Considering that Carson Energy Group represents the most stringent CO BACT which has been achieved in practice, staff recommends a BACT level for CO emissions from simple-cycle gas turbines of 6 ppmvd at 15 percent oxygen averaged over 3 hours.

2. Combined-Cycle and Cogeneration Gas Turbines

The most stringent CO BACT found for a combined-cycle/cogeneration gas turbine was required in the preconstruction permit for Newark Bay Cogeneration Partners in Newark, New Jersey, at 1.8 ppmvd CO at 15 percent oxygen averaged over 1 hour. The determination was made for a 640 MMBtu/hr Westinghouse CW251/B-12 gas turbine using an oxidation catalyst. Compliance with the limits was demonstrated in a 1993 source test. The facility is required to source test every five years; staff at the New Jersey Department of Environmental Protection indicated additional source test results were not available at this time. ARB staff was not able to obtain CEMs data to verify whether the CO emission limit has been met on a continual basis to demonstrate whether the level has been achieved in practice.

The next most stringent CO BACT found for a combined-cycle/cogeneration gas turbine was required in the preconstruction permit for Sacramento Power Authority (Campbell Soup) in Sacramento County, California, at 9.63 lb/hr averaged over 3 hours (equivalent to approximately 2.68 ppmvd VOC as methane at 15 percent oxygen). The determination was made for a 1,257 MMBtu/hr Siemens V84.2 gas turbine using an oxidation catalyst. Two consecutive years of source testing indicate CO emissions vary from 0.50 to 1.89 lb/hr (0.16 to 0.62 ppmvd CO at 15 percent oxygen).

The next most stringent CO BACT found for a combined-cycle/cogeneration gas turbine was required in the preconstruction permit for Sutter Power Plant near Yuba City, California, at 4.0 ppmvd CO at 15 percent oxygen averaged over 24 hours. This determination applied to a 1,900 MMBtu/hr Westinghouse 501F gas turbine nominally rated at 170 MW. This CO emission level is proposed to be achieved using an oxidation catalyst. There is a similar CO BACT proposed for combined-cycle gas turbines at both the 1,048 MW La Paloma Generating Project[9]

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[9]Note that La Paloma Generating Company is taking a tiered approach to limiting CO emissions based on load.

in Kern County, California, and the Pittsburg District Energy Facility in Pittsburg, California. The determinations are for 172 MW Asea Brown Bovari (ABB) KA-24 and 170 MW General Electric Frame 7FA gas turbines, respectively. They require 6.0 ppmvd CO at 15 percent oxygen using 3-hour averaging. The emission level will be achieved using an oxidation catalyst. Although the concentration associated with this determination is slightly less stringent than Sutter Power Plant, the averaging time is considerably shorter.

Based on the above, staff recommends a BACT level for combined-cycle and cogeneration gas turbines of 6.0 ppmvd CO at 15 percent oxygen averaged over 3 hours. Staff intends this CO BACT level to apply to CO nonattainment areas within California. Staff believes that this level of emissions is reasonable given that CO emission violations are primarily caused by concentrated motor vehicle emissions and the majority of California is designated attainment for State and federal CO emissions. The source test results at Sacramento Power Authority and other combined-cycle and cogeneration power plants indicate that 6.0 ppmvd CO at 15 percent oxygen averaged over 3 hours can be easily achieved with an oxidation catalyst. Also, because staff's analysis concludes that there is not sufficient evidence to establish oxidation catalyst contribution to sulfate formation, there is no reason to discount use of an oxidation catalyst for abatement of CO emissions.

IV. POTENTIAL METHODS OF VOC EMISSION CONTROL

1. VOC Formation Mechanism

Similar to CO emissions, VOC emissions result from incomplete combustion. VOC emissions are released in the exhaust flue gas when some of the hydrocarbon fuel remains unburned or is partially burned during combustion.

B. Combustion VOC Controls

Generally, maximizing the time, temperature, and turbulence, provides for more efficient combustion and reduced VOC emissions. Residence time is the amount of time for the combustion gases to flow through the combustor. The residence time can be increased by augmenting the length of the combustor. The longer the residence time, however, the more NO_X emissions are produced due to exposure of the combustion gases to high temperatures for increased periods of time.

C. Flue-Gas VOC Controls

1. Oxidation Catalyst

Like CO emissions, VOC emissions have traditionally been abated with combustion controls and oxidation catalysts. In addition, due to low VOC emission concentrations, the control of VOC emissions from gas turbines was relatively unimportant to regulators compared to those of NO_X and CO. As a result, initial control of VOC emissions experienced with oxidation catalysts were more coincidental than intentional since the oxidation catalysts were initially utilized to control CO emissions. Once oxidation catalysts were required for control of VOC, control efficiencies of 40 and 50 percent were apparently possible.

D. Current Stringent SIP Control Measures

Staff is not aware of any SIP control measures designed specifically to limit VOC emissions from gas turbines.

5. Control Techniques Required as BACT

Tables C-9 and C-10 list the most stringent VOC emission controls required as BACT that staff could locate for gas turbines of at least 20 MW fired on natural gas and used in simple-cycle, combined-cycle, and cogeneration power plant configurations.

Table C-9: VOC Emission Controls Required for Simple-Cycle Gas Turbines

Facility and Gas Turbine Description	Permitting	Method of VOC Control	Emission Limits	Approx. Emission Concentration in ppmvd at 15% O_2, as CH_4
Carolina Power & Light Four 1,907.6 General Electric 7231 FA gas turbines	A/C: 1812R18 Issued: 7/31/98 Startup: not built yet	Combustion control	2.8 lb/hr and 0.0015 lb/MMBtu	1.11
Sacramento Cogeneration Authority (Proctor & Gamble) 421.4 MMBtu/hr General Electric LM6000 gas turbine producing 25.24 MW	A/C: 11436 Issued: 8/19/94 Startup: not built yet	Oxidation catalyst	1.1 lb/hr (3-hr average)	1.98

Carson Energy 450 MMBtu/hr General Electric LM6000 gas turbine producing 42 MW. Unit can co-fire with digester gas. Information provided applies to natural gas.	A/C: 11013 Issued: 7/23/93 P/O: 12830 Startup: 1995	Oxidation catalyst	2.46 lb/hr (3-hr average) and 59.1 lb/day	4.14

Table C-10: VOC Emission Controls Required for Combined-Cycle and Cogeneration Gas Turbines

Facility and Gas Turbine Description	Permitting	Method of VOC Control	Emission Limits	Approx. Emission Concentration in ppmvd at 15% O_2, as CH_4
Bear Mountain Limited G.T.E. cogeneration system including Stewart & Stevenson General Electric LM5000 gas turbine with HRSG producing 48 MW	A/C: S-2049-1-2 Issued: 8/19/94 P/O: S-2049-1-2 Issued: 10/4/95	Oxidation catalyst	0.6 ppmvd @ 15% O_2 (3-hr average) and 1.04 lb/hr and 25.0 lb/day	0.6
Sutter Power Plant Two 1,900 MMBtu/hr Westinghouse 501F gas turbines with two 170 MMBtu/hr auxiliary-fired HRSG producing 170 MW each and steam turbine producing 160 MW	CEC Docket: 97-AFC-2 Issued: 4/14/99 Startup: not built yet	Oxidation catalyst	1.0 ppmvd @ 15% O_2 (24-hr average)	1.0
La Paloma Generating Company Four 1,736 MMBtu/hr ABB GT-24 OTC gas turbines producing 172 MW each and four steam turbines producing 90 MW each	A/C: S-3412-1-0, S-3412-2-0, S-3412-3-0, S-3412-4-0 Issued: 5/26/99 Startup: not built yet	Oxidation catalyst (one unit may have SCONOx catalyst)	0.4 ppmvd @ 15% O_2 as propane (3-hr average)	1.1
Brooklyn Navy Yard Cogeneration Two 1,503 MMBtu/hr Siemens V84.2 gas turbines with HRSG producing 121 MW each and two 40 MW steam turbines	A/C: 2-6101-00185 Issued: 6/6/95 P/O: 2-6101-00185 Issued: 11/12/97	W.R. Grace Oxidation catalyst	2.6 lb/hr (1-hr average) and 0.002 lb/MMBtu	1.31
Newark Bay Cogeneration Partnership	A/C: 01-92-5231 to 01-92-5261	Oxidation catalyst	4 ppmvd @ 15% O_2 (1-hr	4

Table C-10: VOC Emission Controls Required for Combined-Cycle and Cogeneration Gas Turbines				
Facility and Gas Turbine Description	Permitting	Method of VOC Control	Emission Limits	Approx. Emission Concentration in ppmvd at 15% O_2, as CH_4
Two 640 MMBtu/hr Westinghouse CW251/B-12 gas turbines	Issued: 6/9/93 P/O: 01-92-5231 to 01-92-5261 Startup: 8/1/93		average) and 0.005 lb/MMBtu and 3.20 lb/hr	
Crockett Cogeneration 1,935 MMBtu/hr General Electric PG7221 (Frame 7FA) gas turbine with 349 MMBtu/hr auxiliary-fired HRSG producing 240 MW	A/C: S-201 Issued: 10/5/93 P/O: S-201 Issued: 12/19/96	Engelhard Oxidation catalyst	CTG: 2.8 lb/hr	1.10
			CTG + DB: 12.9 lb/hr	4.28
Sacramento Power Authority (Campbell Soup) 1,257 MMBtu/hr Siemens V84.2 gas turbine with 200 MMBtu/hr auxiliary-fired HRSG producing 102 MW and 55 MW steam turbine	A/C: 11456 Issued: 8/19/94 P/O: 13629 Startup: 1997	Oxidation catalyst	CTG: 3.21 lb/hr (3-hr average)	1.93
			CTG + DB: 9.01 lb/hr (3-hr average)	4.68
Carson Energy 450 MMBtu/hr General Electric LM6000 gas turbine with 99.8 MMBtu/hr auxiliary-fired HRSG producing 42 MW	A/C: 11012 Issued: 7/23/93 P/O: 12829 Startup: 1995	Good combustion practices	CTG: 2.46 lb/hr (3-hr average) and 59.1 lb/day	4.14
			CTG + DB: 3.75 lb/hr (3-hr average) and 90.2 lb/day	5.16

F. Emission Levels Achieved in Practice

Tables C-11 and C-12 list the most stringent VOC emission levels staff could locate which were achieved by simple-cycle, combined-cycle, and cogeneration power plant gas turbines while combusting natural gas. Note that no tests in either table exceed 2.0 ppmvd at 15 percent oxygen at 100 percent load.

Table C-11: VOC Emission Source Test Results for Simple-Cycle Gas Turbines			
Facility and Gas Turbine Description	Method of VOC Control	Measured Emissions	Approx. Emission Concentration in ppmvd at 15% O_2 as CH_4
Carson Energy 450 MMBtu/hr General Electric LM6000 gas turbine producing 42 MW. Unit can co-fire with digester gas. Information provided applies to natural gas.	Oxidation catalyst	1.08 lb/hr (100% load) 1.21 lb/hr (50% load) in Sep-Oct 1995	1.98 (100% load) 3.77 (50% load)
		(no data @ 100% load) 0.476 lb/hr (50% load) in Nov 1996	1.46 (50% load)
		<0.51 lb/hr (100% load) <0.39 lb/hr (50% load) in Nov 1997-Jan 1998	0.95 (100% load) 1.21 (50% load)

Table C-12: VOC Emission Source Test Results for Combined-Cycle and Cogeneration Gas Turbines			
Facility and Gas Turbine Description	Method of VOC Control	Measured Emissions	Approx. Emission Concentration in ppmvd at 15% O_2 as CH_4
Bear Mountain Limited G.T.E. cogeneration system including Stewart & Stevenson General Electric LM5000 gas turbine with HRSG producing 48 MW	Oxidation catalyst	<0.8 ppmvd @ 15% O_2 in Apr 1998	0.8
Brooklyn Navy Yard Cogeneration Two 1,503 MMBtu/hr Siemens V84.2 gas turbines with HRSG producing 121 MW each and two 40 MW steam turbines	W.R. Grace Oxidation catalyst	<0.67 ppmvd and <0.71 ppmvd @ 15% O_2 in 1996	0.67 and 0.71
Carson Energy 450 MMBtu/hr General Electric LM6000 gas turbine with auxiliary-fired HRSG producing 42 MW.	Good combustion practices	CTG: 0.76 lb/hr (50% load) in Sep-Oct 1995	2.49 (50% load)

Table C-12: VOC Emission Source Test Results for Combined-Cycle and Cogeneration Gas Turbines			
Facility and Gas Turbine Description	Method of VOC Control	Measured Emissions	Approx. Emission Concentration in ppmvd at 15% O_2 as CH_4
		CTG: 0.520 lb/hr (50% load) in Nov 1996	1.85 (50% load)
Crockett Cogeneration		<0.02 lb/hr in Jun 1997	0.00679
1,935 MMBtu/hr General Electric PG7221 (Frame 7FA) gas turbine with 349 MMBtu/hr auxiliary-fired HRSG producing 240 MW	Engelhard Oxidation catalyst	0.116 lb/hr in Jun 1998	0.0406
Newark Bay Cogeneration Partnership Two 640 MMBtu/hr Westinghouse CW251/B-12 gas turbines	Oxidation catalyst	<1 ppmvd @ 15% O_2 in 1993	<1
Sacramento Power Authority (Campbell Soup)		CTG + DB: <1.42 lb/hr in Oct 1997	<0.8
1,257 MMBtu/hr Siemens V84.2 gas turbine with 200 MMBtu/hr auxiliary-fired HRSG producing 102 MW and 55 MW steam turbine	Oxidation catalyst	CTG + DB: 4.60 lb/hr in Oct 1998	1.79

G. More Stringent Control Techniques

Staff is not aware of any additional technologically feasible control techniques, existing or under development, to reduce VOC emissions from gas turbines.

H. Effect of Oxidation Catalysts on VOC Emissions and Measurement Issues

Staff has received comments arguing both for and against the use of oxidation catalysts to control VOC emissions. Arguments in favor of requiring an oxidation catalyst as part of the VOC BACT determination were expressed in a June 2, 1999, letter from CURE. The letter argued that collateral VOC emission reductions occur across the oxidation catalyst, depending on the catalyst operating temperature. An Engelhard oxidation catalyst performance curve (included as Figure 2) was provided as support. The curve indicates VOC removal efficiencies of 50 percent and greater. The letter also cites a 1995 source test at the Carson Energy Group in Sacramento County, California, as proof of its argument. The source test indicated VOC emissions of 0.96 lb/hr for the combined-cycle gas turbine without a CO oxidation catalyst, and

0.48 lb/hr for the peaking gas turbine with an oxidation catalyst. The letter also cites the benefit

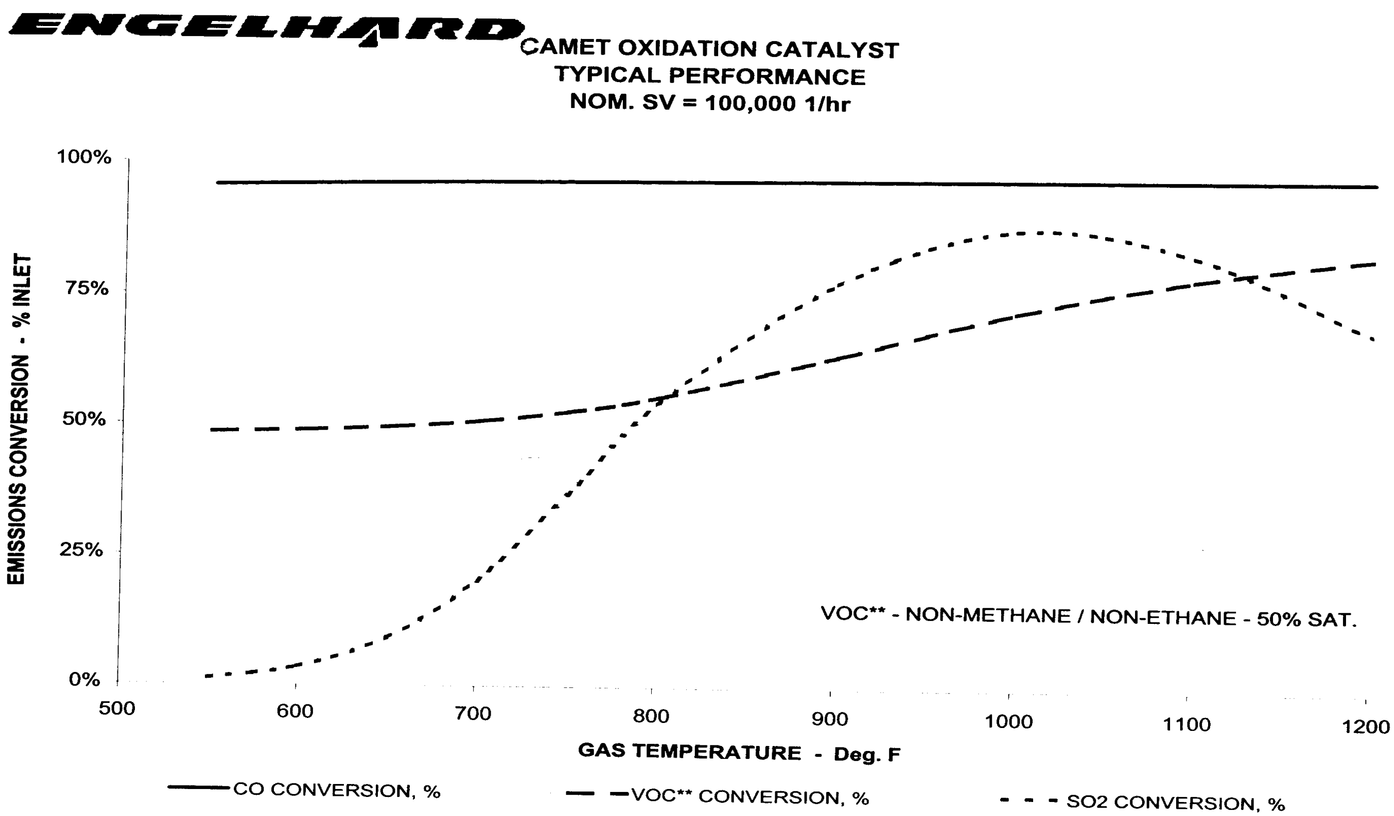

Figure 2 Catalytic Conversion Rates For An Engelhard Camet Oxidation Catalyst

of reduction of toxic emissions from natural gas combustion.

Opposing opinion regarding the benefits of an oxidation catalyst on VOC emissions was provided in a May 17, 1999, letter from Sierra Research. The letter argues that gas turbine vendors provide guarantees for total hydrocarbon emission rates which are on the order of 7 to 10 ppm; however lower levels are proposed by power plant project proponents because most of the hydrocarbons are methane. Project proponents have proposed various VOC levels based on different assumptions made. Some propose VOC emissions of 0.7 to 1.0 ppm based on the assumption that the fraction of methane in the exhaust is equal to the fraction of methane in the natural gas fuel. Others propose 1.4 to 2.0 ppm based on vendor recommendations that 80 percent of total hydrocarbon emissions are methane. Still others propose 3.5 ppm assuming 50 percent of total hydrocarbons in the exhaust are methane. Sierra Research provided a listing of VOC source test results from several gas turbines, most equipped with oxidation catalysts; results ranged from 0.7 to 3.9 ppm. Sierra Research also compares source test results at Carson Energy Group for both catalyst-equipped and non-catalyst controlled gas turbines. The comparison was for testing at 50 percent load which resulted in higher VOC emissions from the catalyst-controlled gas turbine. Sierra Research also challenges the accuracy of VOC test methods at low levels and gives minimum detection limits for various VOC test methods: EPA Method 25 (minimum 50 ppm), EPA Method 25A (varies depending on calibration gas), and SCAQMD Method 25.1 (minimum 25 ppm). Sierra Research acknowledges that there are other test methods that are not included in agency guidelines, but states that they are unaware of any VOC test method with a detection level below 10 ppm. Based on the lack of demonstrated effectiveness from the oxidation catalyst and measurement issues, Sierra Research recommends a VOC BACT level of no less than 3.5 ppmvd at 15 percent oxygen.

Staff does not feel that the source tests conducted at Carson Energy Group provide a good basis for comparing the effect of an oxidation catalyst on VOC emissions from natural gas-firing on two similar gas turbines. Source test data which could be compared are only available when firing at 50 percent load. The combustion inefficiencies associated with lower loads are expected to result in higher emission levels. One hundred percent load conditions were only available for the combined-cycle gas turbine (non-catalyst equipped) while firing on a mixture of natural gas and digester gas. Staff does not feel this data can be adequately compared due to the different fuels.

Staff acknowledge that there has been a lack of use of the most reliable source test methods in assessing VOC emissions from power plant gas turbines in some cases. Staff agrees that EPA Method 25 was not designed to measure levels below 50 ppm. Therefore, EPA Method 25 is inappropriate for the level of VOC emissions expected from gas turbines. Staff of the SCAQMD confirmed that SCAQMD Method 25.1 is no longer used by the district. Instead a revised version, SCAQMD Method 25.3, is applied. The method protocol is currently in review with U.S. EPA. SCAQMD Method 25.3 has sensitivities that can measure effectively down to as low as 1 ppm.

District representatives and private source testers have confirmed that there are reliable source test methods available to measure VOC emissions below 10 ppm. For example, EPA Method 25A can measure down to the 1 ppm level, and perhaps, even as low as 0.5 ppmvd for alkanes, alkenes, and arenes, with a highly sensitive flame ionization detector (FID).[10] One drawback is that Method 25A will tend to underestimate VOC levels where polar organics are present. Another option for acceptable VOC emission measurement is EPA Method 18.

VOC emissions data from available combined-cycle/cogeneration gas turbine source tests, using acceptable methods, consistently indicate emissions no greater than 2.0 ppmvd VOC at 15 percent oxygen have been achieved with the application of an oxidation catalyst.

I. Discussion and Recommendations

1. Simple-Cycle Gas Turbine

The most stringent VOC BACT for a simple-cycle gas turbine was required in the preconstruction permit for Carolina Power & Light in Goldsboro, North Carolina, at 0.0015 lb/MMBtu (equivalent to approximately 1.11 ppmvd VOC as methane at 15 percent oxygen). The determination was made for a 1,907.6 MMBtu/hr General Electric 7231 FA gas turbine using combustion control while firing on natural-gas fuel. A recent conversation with the permitting engineer at the North Carolina Department of Environment and Natural Resources in May 1999 confirmed that the facility had not commenced operation yet.

The next most stringent VOC BACT found for a simple-cycle gas turbine was required in the preconstruction permit for Sacramento Cogeneration Authority (Proctor & Gamble) in Sacramento County, California, at 1.1 lb/hr (equivalent to approximately 1.98 ppmvd VOC as methane at 15 percent oxygen). The determination was made for a 421.4 MMBtu/hr General Electric LM6000 gas turbine using an oxidation catalyst. Air district staff confirmed in April 1999 that the simple-cycle gas turbine had not been installed yet.

The next most stringent VOC BACT found for a simple-cycle gas turbine was required in the preconstruction permit for Carson Energy Group in Sacramento County, California, at 2.46 lb/hr (equivalent to approximately 4.14 ppmvd VOC as methane at 15 percent oxygen). The determination was made for a 450 MMBtu/hr General Electric LM6000 PA gas turbine using an oxidation catalyst. This gas turbine has been in operation since 1995. Three consecutive years of source testing at Carson Energy Group indicate VOC emissions vary from 0.51 to 1.08 lb/hr averaged over 3 hours (0.95 to 1.98 ppmvd VOC as methane at 15 percent oxygen).

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[10] Personal communications with Dr. Eric D. Winegar of Applied Measurement Science.

Based on the above, the most stringent BACT requirements are in the 1 to 2 ppmvd VOC at 15 percent oxygen range. Source tests at Carson Energy Group demonstrate VOC emission levels of no more than 2 ppmvd at 15 percent oxygen can be met on a consistent basis. Therefore, staff recommends a BACT emission level for VOC from simple-cycle gas turbines of 2 ppmvd at 15 percent oxygen averaged over 3 hours.

2. Combined-Cycle and Cogeneration Gas Turbine

The most stringent VOC BACT for a combined-cycle/cogeneration gas turbine was required in the preconstruction permit for Bear Mountain Limited in Kern County, California, at 0.6 ppmvd VOC at 15 percent oxygen. The determination was made for a 48 MW General Electric LM5000 gas turbine using a CO oxidation catalyst. The last source test resulted in emissions of less than 0.8 ppmvd VOC at 15 percent oxygen.

The next most stringent VOC BACT for a combined-cycle/cogeneration gas turbine is proposed for the High Desert Power Plant in San Bernardino County, California, at 1.0 ppmvd VOC at 15 percent oxygen averaged over 1 hour. The power plant will consist of either two or three gas turbines, with total power plant output nominally rated at 700 or 750 MW. This VOC emission level is proposed to be achieved using a CO oxidation catalyst with approximately 40 percent VOC destruction efficiency.

The next most stringent VOC BACT found for a combined-cycle/cogeneration gas turbine was required in the preconstruction permit for Sutter Power Plant near Yuba City, California, at 1.0 ppmvd VOC at 15 percent oxygen averaged over 24 hours. The determination was made for a 1,900 MMBtu/hr Westinghouse 501F gas turbine nominally rated at 170 MW. This VOC emission level is proposed to be achieved using a CO oxidation catalyst. The Sutter Power Plant was approved by the California Energy Commission (CEC) on April 14, 1999.

There is a similarly stringent VOC BACT proposed for combined-cycle gas turbines at the 1,048 MW La Paloma Generating Project in Kern County, California. This determination is for an Asea Brown Bovari (ABB) KA-24 gas turbine nominally rated at 172 MW. It requires 0.4 ppmvd as propane[11] at 15 percent oxygen using 3-hour averaging. This emission level will be achieved using an oxidation catalyst. Although the concentration associated with this determination is slightly less stringent than that for Sutter Power Plant, the averaging time is considerably shorter.

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[11] VOC concentration given as 0.4 ppmvd as propane is approximately equal to 1.1 ppmvd as methane.

Two years of source testing at Crockett Cogeneration in Crockett, California, indicate VOC emissions vary from about 0.007 to 0.085 ppmvd precursor organic compound (POC) as methane at 15 percent oxygen over a 1-hour average. The 249 MW plant consists of a combined-cycle General Electric Frame 7FA combustion gas turbine with an oxidation catalyst. The 0.007 ppmvd VOC level corresponds to the sensitivity threshold of the source test method. Bay Area staff indicated a more appropriate characterization of the measured value is as less than 1 ppmvd at 15 percent oxygen.[12]

Staff calculations estimate uncontrolled VOC emissions from gas turbines of approximately 4 ppmvd at 15 percent oxygen.[13] Using a conservative estimate of VOC emission control from the oxidation catalyst of 50 percent, the emission level is 2.0 ppmvd VOC at 15 percent oxygen. Available source tests at Crockett Cogeneration and other similar power plants consistently indicate emissions of no greater than 2.0 ppmvd VOC at 15 percent oxygen averaged over 1 hour with use of an oxidation catalyst. Based on the above, staff recommends a BACT level of 2.0 ppmvd VOC at 15 percent oxygen averaged over 1 hour (or equivalent limit of 0.0027 lb VOC/MMBtu, higher heating value) for combined-cycle and cogeneration gas turbines.

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[12]Personal communications with Ken Lim of the Bay Area Air Quality Management District.

[13]Based on U.S. EPA AP-42 Chapter 3.1, "Stationary Gas Turbines for Electricity Generation," January 1995 edition.

V. POTENTIAL METHODS OF PM_{10} EMISSION CONTROL

A. General Concerns in Controlling PM_{10} Emissions from Gas Turbines

There are a limited number of options for controlling PM_{10} emissions from gas turbines. These emissions are below one micrometer in aerodynamic diameter[14] and diluted by the high volume of exhaust from a turbine. Potential add-on controls such as filtering devices, venturi scrubbers, and electrostatic precipitators would be rendered less effective under these conditions and have to be scaled-up in size. Neither has there been much success in reducing PM_{10} emissions through combustion controls. The only meaningful control of turbine exhaust emissions has been through limiting fuel type and sulfur content.

Gaseous fuels are generally associated with the least PM_{10} emissions due to their lower sulfur, nitrogen, and ash contents. In addition, gaseous fuels can be more easily mixed with the combustion air than liquid fuels, which must be atomized into the combustion mixture and then combusted near the droplet surfaces. Less soot production is expected with gaseous fuels since fuel rich zones of combustion near the droplets are avoided.

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[14]U.S. EPA AP-42, Table 3.1-1 indicates all PM_{10} emissions from gas turbines fired on natural gas are below one micrometer in size. Furthermore 40 percent of the emissions are below 0.10 micrometers in size.

PM_{10} emission rates from gas turbines are relatively low when firing on natural gas. However the importance of PM_{10} emission control for gas-fired gas turbines is changing. Many of the new generation turbines proposed for California power plants are much larger than their predecessors. Even though these new larger turbines generally have lower emission concentrations of PM_{10} [15], their higher emission rates can exceed 70 tons per year. This level of emissions exceeds the major source threshold for PM_{10} in serious nonattainment areas.

B. Current SIP Control Measures

Staff is unaware of any SIP control measures designed specifically to limit PM_{10} emissions from gas turbines.

C. Control Techniques Required as BACT

Although other gaseous fuels are available, natural gas is by far the most prominently used gaseous fuel. In California, BACT decisions often require the use of natural gas, with composition meeting the specifications of the Public Utilities Commission (PUC). Although the PUC allows total sulfur contents up to 5 grains of sulfur per 100 standard cubic feet (5 gr S/100 scf), gas utilities around the State specify levels of 1 gr S/100 scf or less in purchase contracts with natural gas suppliers.

Tables C-13 and C-14 list several PM_{10} emission controls required as BACT for simple-cycle, combined-cycle, and cogeneration power plant configurations. These determinations were mostly found in the CAPCOA BACT Clearinghouse and the EPA RACT/BACT/LAER Clearinghouse. The most stringent BACT limit for simple-cycle gas turbines is 0.00081 grains per dry standard cubic foot (gr/dscf) at 3 percent CO_2 for a Westinghouse gas turbine at Carolina Power and Light. Correspondingly, the most stringent BACT limit for combined-cycle and cogeneration units is 0.00043 and 0.00017 gr/dscf at 3 percent CO_2 (firing a gas turbine with and without, respectively, duct burners) at Sacramento Power Authority (Campbell Soup). The latter BACT limits for Sacramento Power Authority are substantially less than any other limits governing a gas turbine with an auxiliary-fired HRSG. However, Sacramento Power Authority was able to comply with the former limit in both 1997 and 1998.

Table C-13: PM_{10} Emission Controls Required for Simple-Cycle Gas Turbines

Facility and Gas Turbine Description	Permitting	Method of	Emission	Approx.

[15] Proposed PM_{10} emission rates are approximately 12 percent of U.S. EPA AP-42 values for uncontrolled emissions from gas turbines fired on natural gas.

		Method of PM_{10} Control	Emission Limits	Approx. Emission Concentration in gr/dscf at 3% CO_2
Carolina Power and Light 1520 MMBtu/hr Westinghouse gas turbine limited to 2750 hr/yr of operation	A/C: 0820-0033 Issued: 8/31/94 P/O: 0820-0033 Startup: 6/1/96	Natural gas firing	5.9 lb/hr	0.00081
Carolina Power and Light (H.F. Lee Stream Electric Plant) 1907.6 MMBtu/hr General Electric PG 7231FA gas turbine fired on natural gas and #2 fuel oil	A/C: 1812R18 Issued: 7/31/98 Startup: not built yet	Natural gas firing	9 lb/hr	0.0010
Carson Energy GE LM6000 gas turbine producing 42 MW. Unit can co-fire with digester gas, but information here given for firing on natural gas.	A/C: 11013 Issued: 7/23/93 P/O: 12830 Startup: 1995	Natural gas firing	2.5 lb/hr	0.0010
Northern California Power Agency GE Frame 5 gas turbine producing 25.24 MW	A/C: N-583-1-2 Issued: 10/2/97 P/O: N-583-1-2 Issued: 3/23/98	Natural gas firing	0.013 lb/MMBtu	0.0027

Table C-14: PM_{10}. Emission Controls Required for Combined-Cycle and Cogeneration Gas Turbines

Facility and Gas Turbine Description	Permitting	Method of PM_{10} Control	Emission Limits	Approx. Emission Concentration in gr/dscf at 3% CO_2
Sacramento Power Authority (Campbell Soup) Siemens V84.2 gas turbine with auxiliary-fired HRSG producing 102 MW	A/C: 11456 Issued: 8/19/94 P/O: 13629 Startup: 1997	Natural gas firing	CTG: 1.0 lb/hr CTG+DB: 3.0 lb/hr	0.00017 0.00043
Crockett Cogeneration GE Frame 7FA with auxiliary-fired HRSG producing 240 MW in combined-	A/C: S-201 Issued: 10/5/93 P/O: S-201	Natural gas firing	10.8 lb/hr as filterables	0.0012 as filterables

Table C-14: PM_{10}. Emission Controls Required for Combined-Cycle and Cogeneration Gas Turbines				
Facility and Gas Turbine Description	Permitting	Method of PM_{10} Control	Emission Limits	Approx. Emission Concentration in gr/dscf at 3% CO_2
cycle mode	Issued: 12/19/96			
Carson Energy GE LM6000 gas turbine with auxiliary-fired HRSG producing 42 MW. Unit can co-fire with digester gas, but information here given for firing on natural gas	A/C: 11012 Issued: 7/23/93 P/O: 12829 Startup: 1995	Natural gas firing	CTG: 2.5 lb/hr (3-hr average)	0.0012
			CTG+DB: 3.5 lb/hr (3-hr average)	0.0013
Sutter Power Plant Two Westinghouse 501F gas turbines with auxiliary-fired HRSG producing 500 MW	CEC Docket: 97-AFC-2 Issued: 4/14/99 Startup: not built yet	Firing with PUC pipeline-quality natural gas firing	11.5 lb/hr (24-hr average)	0.0013

D. Emission Levels Achieved in Practice

With regard to simple-cycle units, two consecutive annual source tests at Carson Energy in Sacramento County, California, indicate PM_{10} emissions range from 0.00029 to 0.00041 gr/dscf at 3 percent CO_2. The results were obtained on a 102 MW combined-cycle Siemens V84.2 gas turbine. These results indicate that levels of approximately 0.0004 gr/dscf at 3 percent CO_2 has been achieved for simple-cycle gas turbines.

With regard to combined-cycle and cogeneration units, two consecutive annual source tests at Sacramento Power Authority (Campbell Soup) in Sacramento County, California, indicate PM_{10} emissions range from 0.00027 to 0.00042 gr/dscf at 3 percent CO_2. The results were obtained on a 102 MW combined-cycle Siemens V84.2 gas turbine. These results indicate a level of approximately 0.0004 gr/dscf at 3 percent CO_2 has been achieved for combined-cycle and cogeneration units.

Table C-15: PM_{10} Source Test Results for Simple-Cycle Gas Turbines			
Facility and Gas Turbine Description	Method of	Measured Emissions	Approx. Emission

	PM$_{10}$ Control		Concentration in gr/dscf at 3% CO_2
Carson Energy GE LM6000 gas turbine producing 42 MW. Unit can co-fire with digester gas, but information here given for firing on natural gas.	Natural gas firing	0.63 lb/hr in Oct 1995	0.00029
		0.882 lb/hr in Nov 1996	0.00041

Table C-16: PM$_{10}$ Source Test Results for Combined-Cycle and Cogeneration Gas Turbines

Facility and Gas Turbine Description	Method of PM$_{10}$ Control	Measured Emissions	Approx. Emission Concentration in gr/dscf at 3% CO_2
Sacramento Power Authority (Campbell Soup) Siemens V84.2 gas turbine with auxiliary-fired HRSG producing 103 MW	Natural gas firing	CTG+DB: 1.93 lb/hr in Oct 1997	0.00027
		CTG+DB: 2.98 lb/hr in Oct 1998	0.00042
Federal Cold Storage Cogeneration General Electric LM2500 gas turbine plus HRSG rated at 32 MW	Natural gas firing	0.0013 gr/dscf at 12% CO_2 on 6/12/97	0.00033
Crockett Cogeneration General Electric Frame 7FA producing with auxiliary fired HRSG rated at 260 MW	Natural gas firing	A maximum of 3.3 lb/hr was measured in two sets of three tests in 1997 and 1998	0.00035 as filterables
Carson Energy GE LM6000 gas turbine with auxiliary-fired HRSG producing 42 MW. Unit can co-fire with digester gas, but information here given for firing on natural gas	Natural gas firing	1.01 lb/hr in Oct 1995	0.00038
		2.08 lb/hr in Nov 1996	0.00079

E. More Stringent Control Techniques

Staff is not aware of any additional technologically feasible control techniques, existing or under development, to reduce PM$_{10}$ emissions from gas turbines.

F. PM$_{10}$ Measurement Concerns

1. Measurement of Filterable PM_{10} Emissions

According to conversations with power plant applicants and representatives, filterable PM_{10} emission concentrations for power plants are so low that source tests must occasionally be extended to collect enough sample. In addition, this level of emission is approaching limits of detection.

2. Measurement of Condensible PM_{10} Emissions

There are concerns that artifact PM_{10} in the form of sulfate is formed from absorbed SO_X in impingers used for measuring condensible PM_{10}. Staff is unaware of evidence for the occurrence and amount of SO_X absorption, but does not deny the probability of its existence. Although theoretical arguments for artifact sulfate formation in impingers is compelling, the amount of absorption has not been verified with any actual measurements, leaving any estimates very speculative.

G. Discussion and Recommendations

PM_{10} emissions are partially dependent on fuel composition. In addition to ash, other constituents of concern include fuel-bound sulfur and nitrogen. Natural gas has negligible amounts of all three constituents when compared to liquid or solid fuels. As a result, there should be minimal nitrate and sulfate production. Furthermore, the production of any thermally-induced nitrates and the organic fraction of PM_{10} can best be abated through the use of combustion controls. Therefore, for new gas turbines with state-of-the-art combustion design, PM_{10} emissions are most effectively reduced using natural gas fuel with low sulfur content.

Staff is unaware of any add-on control technologies that are feasible for reducing PM_{10} emissions in gas turbine flue gas. As a result, the lowest PM_{10} emissions are achieved through combustion of natural gas along with combustion design that minimizes NO_X and unburned hydrocarbons. Applicants have the ability to select a low-sulfur fuel, such as natural gas; however, only the gas supplier has the ability to limit fuel sulfur content.[16] Natural gas utility companies have the ability to specify fuel sulfur content in purchase contracts with gas suppliers. Two major California natural gas utility companies, i.e., Pacific Gas & Electric and Southern California Gas, use purchase contracts that specify levels no higher than 1 gr S/100 scf. Staff believe this represents a limiting circumstance in the maximum emission level of the sulfate portion of PM_{10}.

Considering the above, the default PM_{10} BACT requirement for simple-cycle, combined-

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[16] Under California Public Utilities Commission General Order 58-8, the total sulfur of gas supplied by any gas utility for domestic, commercial, or industrial purposes is limited to 5 grains of total sulfur per 100 standard cubic feet.

cycle, and cogeneration gas turbines is natural gas containing no more than 1 gr S/100 scf of total sulfur. In addition, staff believes that appropriate combustion controls and low sulfur fuel are essential components of a PM_{10} BACT determination for a gas turbine. Any emission limit required for BACT should correspond with a fuel gas sulfur content of 1 gr S/100 scf. Furthermore, there are "housekeeping measures" that can prevent emissions from the lube oil vent, including a lube oil vent coalescer and an associated opacity limit of 5 percent. These latter provisions were required at Badger Creek Limited on a 457.8 MMBtu/hr General Electric LM-5000 gas turbine cogeneration unit with a 48.5 MW capacity.

An example of a recent PM_{10} BACT limit on a large combined-cycle gas turbine was applied to the Sutter Power Plant. A PM_{10} limit of 11.5 lb/hr averaged over 24 hours assuming a fuel sulfur content of 0.7 gr S/100 scf and a 10 percent conversion of fuel sulfur to sulfate emissions. Staff calculations indicate that this limit is equal to an emission concentration of 0.00122 gr/dscf of exhaust gas at 3 percent CO_2. This determination applied to a Westinghouse 501F gas turbine nominally rated at 170 MW. In this case, the applicant presumed fuel sulfur content is below the 1 gr S/100 scf specified in the local gas utility company purchase contracts. Therefore, the applicant assumed the risk associated with fuel sulfur content excursions over 0.7 gr S/100 scf.

VI. Control of SO_X Emissions

A. General Concerns Regarding the Control of SO_X from Gas Turbines

Fuel sulfur is the source of SO_X emissions from gas turbines fired on natural gas. Since the sulfur content is so low, the natural gas odorant substantially contributes to the fuel sulfur content. SO_X emission concentrations are normally below 1 ppmvd for gas turbines fired on California natural gas. Controlling such low SO_X emissions is not feasible.

Since SO_X emissions are highly dependent on fuel sulfur content, the lowest emissions are achieved through the combustion of fuels with the lowest sulfur. Although an applicant can select a low-sulfur fuel, such as natural gas, the applicant does not have control of fuel sulfur contents lower than that specified in contracts between gas utilities and gas suppliers. Entities regulated by the PUC in California have purchase contracts with an effective maximum of total sulfur content for natural gas of 1 gr S/100 scf (equivalent to approximately 17 ppmv S). The most stringent BACT required for a combined-cycle gas turbine is firing of low-sulfur natural gas. The natural gas should contain no more than 1 gr S/100 scf.

2. Current SIP Control Measures

Several California districts have SIP control measures limiting sulfur compounds (as sulfur dioxide) from fossil fuel-burning equipment used generally for the production of useful heat or power.[17] The most stringent of these limits restrict sulfur dioxide emissions to no more than 200 lb/hr. This level of emissions is not approached with gaseous fuel combustion.

C. Control Techniques Required as BACT

SO_X BACT determinations for gas turbines are presented in Tables C-17 and C-18. The most stringent limit for simple-cycle gas turbines was 0.10 ppmvd at 15 percent oxygen on a General Electric Frame 7FA at H.F. Lee Steam Electric Plant. The most stringent limit for combined-cycle and cogeneration units was 0.12 ppmvd at 15 percent O_2 averaged over 3 hours. This limit was required at Sacramento Power Authority (Campbell Soup) for a 1,257 MMBtu/hr Siemens V84.2 gas turbine with a supplemental firing capacity of 200 MMBtu/hr and a total output of 157 MW.

Table C-17: SO_X (as SO_2) Emission Controls Required for Simple-Cycle Gas Turbines

Facility and Gas Turbine Description	Permitting	Method of SO_X Control	Emission Limits	Approx. Emission Concentration in ppmvd at 15% O_2
Carolina Power and Light (H.F. Lee Stream Electric Plant) General Electric PG 7231FA simple-cycle gas turbine fired on natural gas and #2 fuel oil and rated at approximately 170 MW	A/C: 1812R18 Issued: 7/31/98 Startup: not built yet	Natural gas firing	1 lb/hr	0.10

Table C-18: SO_X (as SO_2) Emission Controls Required for Combined-Cycle and Cogeneration Gas Turbines

Facility and Gas Turbine Description	Permitting	Method of SO_X Control	Emission Limits	Approx. Emission Concentration in ppmvd at 15% O_2

[17] Such rules may only apply to cogeneration and combined-cycle units. Others may apply more generally and may cover simple-cycle gas turbines.

Table C-18: SO_X (as SO_2) Emission Controls Required for Combined-Cycle and Cogeneration Gas Turbines				
Facility and Gas Turbine Description	Permitting	Method of SO_X Control	Emission Limits	Approx. Emission Concentration in ppmvd at 15% O_2
Sacramento Power Authority (Campbell Soup) Siemens V84.2 gas turbine with auxiliary-fired HRSG producing 103 MW	A/C: 11456 Issued: 8/19/94 P/O: 13629 Startup: 1997	Natural gas firing	CTG: 0.75 lb/hr (3-hr average)	0.12
			CTG+DB: 0.87 lb/hr (3-hr average)	0.12
Bear Mountain Ltd. GE LM5000 with HRSG rated at 48 MW	A/C: S-2049-1-2 Issued: 8/19/94 P/O: S-2049-1-2 Issued: 10/4/95	Natural gas firing	7.2 lb/day (Not a BACT requirement)	0.13
PDC-El Paso Milford LLC Two ABB GT-24 gas turbines with HRSGs with a total rated output of 544 MW	A/C: 105-0068, 105-0069 Issued: 4/16/99 Startup: not built yet	Natural gas firing	0.0022 lb/MMBtu	0.42
Newark Bay Cogeneration Partnership, L.P. Westinghouse CW251/B-12 gas turbines rated at 68 MW	A/C: 01-92-5231 to 01-92-5261 Issued: 6/9/93 P/C: 01-92-5231 to 01-92-5261 Startup: 8/1/93	Natural gas firing	0.0026 lb/MMBtu	0.51
Carson Energy GE LM6000 gas turbine with auxiliary-fired HRSG producing 42 MW. Unit can co-fire with digester gas, but information here given for firing on natural gas	A/C: 11012 Issued: 7/23/93 P/O: 12829 Startup: 1995	Natural gas firing	CTG: 1.42 lb/hr (3-hr average) (Not a BACT Requirement)	0.63
			CTG+DB: 2.78 lb/hr (3-hr average)	1.0
Sutter Power Plant Two Westinghouse 501F gas turbines	CEC Docket: 97-AFC-2 Issued: 4/14/99	Firing with PUC pipeline-quality natural	1 ppmvd at 15% O_2 (24-hr average)	1

Table C-18: SO_X (as SO_2) Emission Controls Required for Combined-Cycle and Cogeneration Gas Turbines				
Facility and Gas Turbine Description	Permitting	Method of SO_X Control	Emission Limits	Approx. Emission Concentration in ppmvd at 15% O_2
with auxiliary-fired HRSG producing 500 MW	Startup: not built yet	gas firing		

D. Emission Levels Achieved in Practice

SO_X source tests for large gas turbines fired on natural gas are very rare. There were not enough such tests to evaluate what levels have been achieved in practice. Although several source test summaries were available, sufficiently complete data could not be obtained, with the exception of the SO_X source test at Harbor Cogeneration for a General Electric Frame 7 gas turbine rated at 82.345 MW. The measured emission concentration was 0.06 ppmvd at 15 percent oxygen.

E. More Stringent Control Techniques

1. Technologically Feasible Controls

SCOSOx is a catalytic sulfur removal system that works in conjunction with the SCONOx system to remove sulfur compounds from combustion exhaust streams. It is nearly identical to the SCONOx catalyst for NO_X removal except that it favors sulfur compound absorption and is installed upstream of the SCONOx catalyst. SCOSOx was installed in early 1999 at the Genetics Institute in Andover, Massachusetts, in conjunction with SCONOx. The 5 MW cogeneration plant consists of a 65 MMBtu/hr Solar Taurus Model 60 gas turbine with auxiliary-fired HRSG. The SCOSOx system was installed as a "guard bed" for the SCONOx system to enhance the control effectiveness of the NO_X catalyst. In this case, sulfur removal was not measured. Therefore, there is no opportunity to assess any SO_X emissions reductions associated with SCOSOx at this time. Goal Line Environmental Technologies is now supplying the SCOSOx catalyst automatically with the SCONOx technology.

2. Developing SO_X Control Technologies

Staff is not aware of any control technologies currently in development that would be applied to power plant gas turbines to specifically abate SO_X emissions.

F. Discussion and Recommendations

SO_X emissions result from the oxidation of fuel sulfur during combustion. Staff is unaware of combustion or demonstrated add-on controls feasible for controlling SO_X emissions from gas turbines. Therefore, staff recommends a SO_X BACT limit equivalent to gaseous fuel with a sulfur content of 1 gr S/100 scf. Based on mass balance calculations and assuming no fuel sulfur conversion to sulfate, a gas turbine firing on natural gas with this level of sulfur content will emit a maximum 0.55 ppmvd SO_X (as SO_2) at 15 percent oxygen. The district determination may also wish to require as BACT, compliance with a fuel sulfur content limit, especially if the content limit is below purchase specification used by the gas utility. In addition, staff suggests that an emission concentration limit corresponding to the assumed fuel sulfur content, i.e., 0.55 ppmvd at 15 percent oxygen or lower, may be appropriate.

APPENDIX C LIST OF ACRONYMS AND ABBREVIATIONS

Acronym	Acronym Meaning
A/C	Authority to Construct (e.g., permit to construct, preconstruction permit)
ARB	(California) Air Resources Board
BACT	best available control technology
BARCT	best available retrofit control technology
Btu	British thermal unit
CAPCOA	California Air Pollution Control Officers Association
CEC	California Energy Commission
CEMs	continuous emissions monitors
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
CTG	combustion turbine generator
DB	duct burner
dscf	dry standard cubic foot (feet)
FDOC	Final Determination of Compliance
gr	grains
H_2O	water
hr	hour
HRSG	heat recovery steam generator
LAER	lowest achievable emission rate
lb	pound(s)
MM	prefix used for million
MMBtu	million British thermal units
MW	megawatts
NO_X	oxides of nitrogen
$PM_{2.5}$	particulate matter with an aerodynamic diameter of 2.5 microns or less
PM_{10}	particulate matter with an aerodynamic diameter of 10 microns or less
P/O	Permit to Operate
POC	precursor organic compounds
ppm	parts per million
ppmvd	parts per million dry volume
PUC	Public Utilities Commission
RACT	reasonably available control technology
ROG	reactive organic gases
scf	standard cubic foot (feet)
SCR	selective catalytic reduction
SIP	state implementation plan
SO_2	sulfur dioxide

APPENDIX C LIST OF ACRONYMS AND ABBREVIATIONS (CONTINUED)

Acronym	Acronym Meaning
SO_X	oxides of sulfur
VOC	volatile organic compounds
U.S. EPA	United States Environmental Protection Agency

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